OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 6, 2007**

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THROUGH: Matt Paque, Supervising Attorney, Air Quality Division

THROUGH: Kendal Stegmann, Senior Environmental Manager, Compliance and Enforcement

THROUGH: Grover Campbell, P.E., Existing Source Permits Section

THROUGH: Phil Martin, P.E., New Source Permits Section

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Construction Permit Application No. **98-172-C (M-19) (PSD)**
Valero Refining Company - Oklahoma
Valero Ardmore Refinery (SIC 2911)
Ardmore, Carter County
Latitude: 34.206° N Longitude: -97.104° W
Directions from I-35: east three miles on Highway 142

SECTION I. INTRODUCTION

Valero Refining Company – Oklahoma (Valero), has requested a modified construction permit to incorporate changes to Permits No. 98-172-C (M-15) (PSD) and 98-172-C (M-18) (PSD). The following are the changes requested by TPI:

1. Change the CO emission limits for the FCCU;
2. Correct the NO_X emission limit for the FCCU;
3. Remove Emission Units T-1081 and B-252 which have been removed from service and dismantled;
4. Remove the CO concentration limit for the continuous catalytic regenerator (CCR) from the permit;
5. Increase the allowable CO emission limit for the CCR;
6. Change the NO_X emission factor for H-15001 from 0.037 lb/MMBTU to 0.06 lb/MMBTU; and
7. Remove certain throughput limitations on some of the process units that are regulated by the throughput of other process units.

This permit will incorporate the majority of the emission units (EU) at the facility, combining the two previously issued construction permits, and address the requested changes. Permits No. 98-172-C (M-15) (PSD) and 98-172-C (M-18) (PSD) will be superseded by this permit. This permit will not reiterate all of the review that was conducted under both of these permits. This permit will incorporate those applicable sections that apply to the listed modifications. However, all of the specific conditions from both of these permits will be incorporated into this permit. Annual rates and emissions are based on 365 days per year.

SECTION II. PROCESS DESCRIPTIONS

The Valero Ardmore Refinery's primary standard industrial classification (SIC) code is 2911. The refinery processes medium and sour crude oils from both the domestic and foreign markets. Major production and processing units include the following: an 100 thousand barrel per day (MBPD) crude unit, a 34 MBPD vacuum-tower unit, a 14 MBPD asphalt blow-still unit, a 11.4 MBPD polymer modified asphalt (PMA) unit, a 32 MBPD distillate heavy-oil desulfurization (DHDS) unit, a 32 MBPD catalytic feed hydrotreater (CFHT) unit, a 30 MBPD fluid catalytic cracker unit (FCCU) with two-stage regeneration, a 33 MBPD naphtha hydrotreater (NHT) unit, a 26 MBPD catalytic reformer unit, a 16 MBPD Sat-Gas Unit, a 7.5 MBPD alkylation unit, a 7.5 MBPD isomerization unit, a 119 long ton per day (LTPD) sulfur recovery unit (SRU), a 130 LTPD SRU and a 26 million standard cubic feet per day (MMSCFD) hydrogen production unit. The majority of raw crude oil is received on-site through utilization of an integrated pipeline system. Emissions are based on these processing and production rates.

To effect operations, the refinery's process heaters, steam boilers, compressors, and generators are capable of producing approximately 1.6 billion BTU/hr of energy transfer. The refinery has approximately 2.4 million barrels of refined product storage capability. Products include conventional and reformulated low sulfur gasoline, diesel fuel, asphalt products, propylene, butane, propane, and sulfur. Refined products are transported via pipeline, railcar, and tank truck.

A. General Function Of Petroleum Refining

Basically, the refining process does four types of operations to crude oil:

1. <u>Separation</u>: Liquid hydrocarbons are distilled by heat separation into gases, gasoline, diesel fuel, fuel oils, and heavier residual material.
2. <u>Conversion</u>:
    - i. *Cracking*: This process breaks or cracks large hydrocarbons molecules into smaller ones. This is done by thermal or catalytic cracking.
    - ii. *Reforming*: High temperatures and catalysts are used to rearrange the chemical structure of a particular oil stream to improve its quality.
    - iii. *Combining*: Chemically combines two or more hydrocarbons such as liquid petroleum gas (LPG) materials to produce high grade gasoline.
3. <u>Purification</u>: Converts contaminants to an easily removable or an acceptable form.
4. <u>Blending</u>: Mixes combinations of hydrocarbon liquids to produce a final product(s).

B. Description of Individual Processes

Crude Unit

The Crude Unit receives a blended crude charge from sweet and sour crude oil feedstock. The crude charge is heated, desalted, heated further, and then fed into the atmospheric tower where separation of light naphtha, heavy naphtha, kerosene, diesel, atmospheric gas oil and reduced crude takes place. The reduced crude from the bottom of the atmospheric tower is pumped through the diesel stripper reboiler and directly to the vacuum tower pre-heater.

After the vacuum tower pre-heater processes the reduced crude, the reduced crude is then processed in the Vacuum Unit to achieve a single stage flash vaporization. A single-stage flash vaporization of the heated reduced crude yields a hot well oil, a light vacuum gas oil, a heavy vacuum gas oil, slop wax, and a vacuum bottoms residual that may be charged to the asphalt blowstill for viscosity improvement or pumped directly to asphalt blending.

DHDS Unit

The DHDS Unit consists of a feed section, reactor section, effluent separator section, recycle gas amine treating section, and a fractionation section. In the feed section, diesel and gas oil are fed to the unit from the Crude Unit main column. From the feed section, the mixed streams are fed to the reactor section. The feed exchanges heat with the feed/reactor effluent exchangers and is charged to the reactor charge heater. From the charge heater, the heated feed passes through a reactor bed where the sulfur and nitrogen are removed. Once the feed leaves the reactor section, it then must be separated in the reactor effluent separator section. The hydrogen gas and hydrocarbon liquid are separated. The hydrogen gas flows to the recycle gas amine treating section where the hydrogen sulfide (H_2S) rich gas stream is cleaned using amine to absorb the sour gas. The hydrocarbon liquid flows to the stripping section of the DHDS unit.

In the stripping section, any LPG with H_2S that is left in the liquid hydrocarbon stream is stripped out with steam. Once the feed has been through the stripping section, it is preheated and fed to the fractionator tower where the kerosene, diesel and gas oil products are fractionated out to meet product specifications.

Saturated-Gas Unit

The feedstock to the Sat-Gas Plant is made up of crude oil atmospheric tower overhead liquid product and the platformer debutanizer overhead liquid product. The debutanizer feed is pumped from the debutanizer feed drum to the 40-tray debutanizer. The de-butanized light straight run gasoline leaves the bottom of the debutanizer and is sent to the NHT Unit. The condensed overhead stream is pumped to the 30-tray de-ethanizer. Ethane, H_2S, and lighter components are removed in the overhead stream and sent to the unsaturated gas treating area in the FCCU. The de-ethanizer bottoms stream that contains propane and butanes is sent to the saturate C_3/C_4 extractor for mercaptan removal and then to the de-propanizer. The condensed liquid from the de-propanizer overhead accumulator is sent to the propane dryer and then to storage. The de-propanizer bottoms stream is sent to the de-isobutanizer located at the Alky Unit for separation of iso-butane and normal butane.

Alkylation Unit
The purpose of this unit is to produce high-octane gasoline by catalytically combining light olefins with isobutane in the presence of hydrofluoric (HF) acid. The mixture is maintained under conditions selected to maximize alkylate yield and quality. The alkylate produced is a branched chain paraffin that is generally the highest quality component in the gasoline pool. Besides the high octane, the alkylate produced is clean burning and has excellent antiknock properties. Propane and butane are byproducts.

NHT Unit
The purpose of this unit is to remove the sulfur, nitrogen, and water from the Platformer and Penex (Isomerization) charge stocks. These are contaminants to the Platformer and Penex catalysts. This is accomplished by passing the naphtha feed stocks over hydrotreating catalyst at elevated temperatures in the presence of hydrogen at high pressures. Under these conditions, the sulfur and nitrogen components are converted to H_2S and ammonia (NH_3), which are then easily removed from the liquid effluent by distillation stripping. Removal of the contaminants provides clean charge stocks to the Platformer and Penex units, which increases the operational efficiency of both units.

The equipment to be installed under Permit No. 98-172-C (M-18) (PSD), two additional reactors and the supporting peripheral fugitive equipment sources, reduced the space velocity by a factor of four and thus enable more intimate catalyst contact in the presence of hydrogen. This enabled more efficient removal of sulfur from the platformer feedstock.

Platformer Unit
The purpose of this unit is to upgrade low octane naphtha to higher-octane gasoline blending stock. The naphtha is a specific boiling range cut from the Crude Unit. The naphtha is upgraded by using platinum catalyst to promote specific groups of chemical reactions. These reactions promote aromatic formation, which gives the boost in octane. A byproduct from the reactions is hydrogen. The hydrogen is processed to the NHT or CFHT units to aid in hydrotreating of the feedstock(s). The reactions produce light hydrocarbon gases, which are sent to the sat-gas unit.

The CCR section of the Platformer Unit allows the reaction section to operate efficiently while maintaining throughput year round. The CCR continuously regenerates a circulating stream of catalyst from the reactors. During normal operations in the reaction section, catalyst activation is lowered due to feedstock contaminants and coke buildup. The regeneration section continuously burns off the coke deposit and restores activity, selectivity and stability to essentially fresh catalyst levels.

Isomerization Unit
The purpose of this unit is to increase the octane of light naphtha. The octane is increased by catalytically rearranging straight chain hydrocarbons to branched hydrocarbons. This process is called "isomerization." The bulk of the products from the unit are the isomerates (C_5's and C_6's), which are added to the refinery's gasoline blending pool. The advantage of using isomerate is good motor octane, benzene saturation, and aromatic reduction. There will be a small yield of light hydrocarbons, which are added to the refinery fuel gas system.

CFHT

Hydrotreating is a process to remove impurities present in hydrocarbons and/or catalytically stabilize petroleum products by reacting them with hydrogen. The CFHT has two primary functions: 1) improve the quality of the feed to the FCCU by removing impurities (metals, sulfur, and nitrogen), and 2) increasing the hydrogen content by saturating the aromatics in the gas oils and light cycle oil feedstocks.

Feed to the CFHT enters the unit from several sources: high sulfur diesel from the storage vessels; light cycle oil from the FCCU; gas oil from the Crude Unit; either vacuum or atmospheric residue from the Crude Unit; and hydrogen from the Hydrogen Unit. The combined liquid feed is filtered and then heated in a series of exchangers before entering the feed surge drum. Liquid feed from the surge drum is pumped to the reaction section of the unit through the multistage charge pump. Hydrogen feed is compressed to the unit operating pressure by two reciprocating compressors. The fresh hydrogen feed along with recycled hydrogen from a steam turbine driven centrifugal compressor combines with the liquid feed in the reaction section of the unit.

Combined feed to the unit is heated in the reactor charge heater and then enters the first of three reactors in series. The reactors each contain a different type of catalyst with a very specific, but complementary role. The primary role of the catalyst in the first two reactors is to remove metals contained in the feed such as nickel and vanadium. The catalyst in the third reactor is primarily designed to convert sulfur and nitrogen species into a form in which they can be removed. The effluent from the reactors then enters a series of separators.

There are four separators in the CFHT: the hot high pressure separator, the hot flash drum, the cold high pressure separator, and the cold flash drum. The primary function of these vessels is to separate the oil from the hydrogen-rich gas in the reactor effluent. Each vessel is operated at different conditions (temperature and pressure) to allow certain components in the reactor effluent to vaporize. Hydrogen recovered in the cold high-pressure separator is routed to the recycle gas amine treater. Light ends, such as methane and ethane, are sent to the refinery sour fuel gas system. Water recovered is sent to a sour water stripper. All of the remaining oil is then combined and sent to the fractionation section of the unit.

Hydrogen recovered from the reactor effluent contains H_2S. The unit is designed to have 0.5-1.0% H_2S in the recycle gas. To control the H_2S at the desired level, a portion of the recycle gas is amine treated. Recycle gas enters the bottom of the amine absorber and is contacted by a counter-current flow of amine. The H_2S is absorbed by the amine and sweet hydrogen exits the top of the absorber. Amine exits the bottom of the absorber and is regenerated in the ARU.

The oil from the separators is routed to the fractionation section of the unit. The oil is heated in the fractionator charge heater and then enters the fractionator. The fractionator is a trayed tower. The fractionator separates the oil into three streams: overhead naphtha product, diesel product, and FCCU feed. The diesel product is stripped of light ends and H_2S in the distillate stripper before being sent to storage.

FCCU

The main purpose of the FCCU is to break up heavy hydrocarbons into a mixture of lighter hydrocarbons and then separate the mixture. The major divisions of the plant are the FCCU charge system, the reactor-regenerators, the main (fractionator) column, and the gas concentration unit.

In the FCC Charge System, the feed is collected in a common feedstock surge drum and heated before it is sent to the FCCU. The feedstock comes from four sources: residuum from the vacuum tower, treated gas oil from storage, gas oil from the crude/DHDS unit, and hot gas oil from the CFHT Unit. The hot and cold charge streams are mixed in the charge drum to reach a desired temperature. The outlet stream from this drum combines with the residuum stream and is pumped through the charge heater where, if necessary, the feed is heated. Finally, the feed is sent to the FCCU reactor to effect the desired cracking reactions.

The catalytic cracking for the process is achieved by processing the superheated feedstock with a cracking promoting catalyst. A byproduct, coke, is produced during the cracking reactions. As a result, the catalyst is covered with coke that must be burned off the catalyst. This is achieved in the FCCU No. 1 and No. 2 regenerators. This burning process results in temperatures normally above 1,300°F. The hot catalyst is recirculated through the system to mix with more feed to control the reactor temperature.

The cracked gas oil must be separated into useable products, namely slurry or #6 fuel oil, light cycle oil (LCO) or diesel fuel, FCCU gasoline or blend stock for motor gasoline and light liquefied petroleum gases (LPG) including olefins.

Sour Water Strippers

The purpose of the sour water strippers is to remove H_2S and ammonia from the total sour water inlet stream. The H_2S and ammonia are stripped from the sour water feed as the water travels down the column. Rising steam strips out the H_2S and ammonia gases. These gases are routed to the SRU/SCOT Unit to convert the H_2S gas stream to sulfur and to destroy the ammonia gas in the thermal section of the SRU.

ARU

Methyldiethanolamine (MDEA) is used to recover carbon dioxide (CO_2) and H_2S to form a weak and unstable salt. These processes take place in the fuel gas absorber and amine contactors. Once this weak and unstable amine salt solution is formed, the reaction must be reversed to clean up or regenerate the amine solution. This reaction takes place in the ARU.

The MDEA solution is fed to the tower from the MDEA flash drum. As the solution travels down the tower, the acid gases are stripped as the salt solution is broken down by heat, which is supplied by two steam reboilers at the base of the tower. The lean regenerated MDEA is then pumped back to the lean MDEA surge drum where the low- and high-pressure MDEA charge pumps charge the regenerated amine solution back to the fuel gas absorber and amine contactors.

SRU / SCOT Process
The SRU converts the H_2S stream from the ARU to liquid elemental sulfur to be loaded out by railcar or truck. This process takes place in two general sections: 1) H_2S is converted to sulfur at high temperatures without the aid of catalytic conversion; and 2) sulfur is formed at much lower temperatures with the aid of catalytic conversion.

In section one, high thermal temperatures are maintained by using liquid oxygen, which also aids in the destruction of ammonia contained in the sour water gases which are destroyed in the thermal section of the SRU. In section two, unconverted sulfur is processed through two or more successive catalytic stages. Each stage consists of process gas reheating, sulfur conversion over an activated alumina catalyst and then cooling to condense and recover the sulfur formed.

The SCOT Unit operation is much the same as the MDEA Unit operation. Unprocessed tail gas from the SRU is heated and mixed with a hydrogen rich reducing gas stream. This heated tail gas stream passes through a catalytic reactor where the sulfur compounds are reconverted back to H_2S. Once the tail gases are converted back into a H_2S gas stream, these gases are routed to a quench system where the gases are cooled and the condensed water from the reactor product is routed to the sour water system. The cooled reactor effluent is then fed to an absorber/stripper section where the acid gas comes in contact with an amine solution and is absorbed, regenerated, and reprocessed by the SRU.

Waste Water Treatment Plant (WWTP)
The WWTP is for the purpose of treating refinery wastewater from the various units and tank farm to comply with specific discharge characteristics specified by the refinery National Pollution Discharge Elimination System (NPDES/OKPDES) permit. The system is comprised of an oily water sewer collection system from the various units and the tank farm, a lift station, two above ground oil water separation tanks, two aggressive bio-reaction tanks, 16 aerated lagoons and two clarifier lagoons. The system treats approximately 600,000 gallons of wastewater daily.

Product Movement Storage Vessel Farm
The purpose of the tank farm and product movement area is to receive, hold, blend, and ship hydrocarbon products in a safe and efficient manner. The major product groups include crude, intermediate feedstocks, LPG, gasolines, distillates, heavy fuel oil, and asphalts. Distillate and gasoline products are shipped via three outlets. These products are also loaded onto trucks at the truck dock. Various LPG's are loaded and unloaded by truck and rail. Asphalt and heavy fuel oil are primarily shipped by truck, but rail connections can also be used.

SECTION III. EQUIPMENT - EMISSION UNIT (EU) GROUPS

EUG 1 Storage Vessel T-1008

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1008	P-1	Cone	LCO /Slurry	2,089	1975

EUG 2 Storage Vessel T-1018

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1018	P-2	External Floating	Alkylate & Gasoline	62,850	1953

EUG 3 Storage Vessel T-1019

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1019	P-3	External Floating	Alkylate & Gasoline	66,868	1948

EUG 4 Storage Vessel T-153

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-153	P-4	Fixed Roof	FCCU Charge /Asphalt	200,676	2003

EUG 6 Storage Vessel T-1118

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1118	P-6	Cone	Asphalt	79,742	1970

EUG 8 Storage Vessel T-1135

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1135	P-8	Cone	PMA Crosslinking Co-Polymer	362	1968

EUG 14 Storage Vessel T-1082

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1082	P-14	External Floating	Crude Oil	124,714	1974

EUG 15 Storage Vessel T-1083

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1083	P-15	External Floating	Crude Oil	124,714	1974

EUG 16 Storage Vessel T-1084

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1084	P-16	External Floating	Crude Oil	124,714	1978

EUG 17 Storage Vessel T-1085

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1085	P-17	Cone	Slurry /#6 Fuel Oil	55,319	1953

EUG 19 Storage Vessel T-1102 & T-1151

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1102	P-19	Cone	Asphalt /Gas Oil	75,786	1975
T-1151	P-189	Cone	Asphalt	206,979	1953

EUG 20 Storage Vessels T-1111

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1111	P-20	Cone	Asphalt /Fuel Oil /Gas Oil	55,011	1954

EUG 21 Storage Vessel T-1113

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1113	P-22	Cone	Asphalt /Gas Oil	131,005	1959

EUG 22 Storage Vessel T-1115

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1115	P-23	External Floating	Gasoline	27,205	1953

EUG 23 Storage Vessel T-1116

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1116	P-24	External Floating	Gasoline	27,315	1953

EUG 24 Storage Vessel T-1121

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1121	P-27	Cone	Diesel /Jet Fuel /Distillate	40,526	1968

EUG 26 Storage Vessel T-1123

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1123	P-29	External Floating	Gasoline /Diesel	60,766	1968

EUG 27 Storage Vessel T-1124

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1124	P-30	External Floating	Gasoline	111,721	1972

EUG 28 Storage Vessel T-1125

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1125	P-31	External Floating	Gasoline	124,398	1974

EUG 29 Storage Vessel T-1126

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1126	P-32	External Floating	Gasoline	124,412	1974

EUG 30 Storage Vessel T-1127

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1127	P-33	Cone	Diesel / Jet Fuel	80,579	1974

EUG 31 Storage Vessel T-1128

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1128	P-34	Cone	Diesel / Jet Fuel	80,639	1974

EUG 32 Storage Vessel T-1129

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1129	P-35	Cone	Diesel / Jet Fuel	2,113	1975

EUG 33 Storage Vessel T-1130

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1130	P-36	External Floating	Gasoline	79,414	9/1978

EUG 34 Storage Vessel T-1131

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1131	P-37	External Floating	Gasoline /FCCU Gasoline + ISOM + Hydrocracker Naptha	125,100	1979

EUG 35 Storage Vessel T-1132

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1132	P-38	External Floating	Reformate	80,138	1979

EUG 36 Storage Vessel T-1141

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1141	P-39	Cone	Diesel / Kerosene	119,189	1992

EUG 37 Storage Vessel T-1142

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1142	P-40	Cone	Diesel / Kerosene	79,445	1992

EUG 38 Regenerated/Make Up Amine Storage Vessel V-523

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-523	P-41	Cone	Amine	91	1993

EUG 39 Storage Vessel V-815

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-815	P-42	Cone	Wastewater Fallout	1,731	1968

EUG 40 Storage Vessel V-818

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-818	P-43	Cone	Slop Oil	444	1968

EUG 41 Oil-Water Separators V-8801 & V-8802

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-8801	P-44	External Floating	Oil / Water	17,200	1993
V-8802	P-45	External Floating	Oil / Water	17,200	1993

EUG 42 Oil Water Separators T-811, T-812, & T-814

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-811	P-46	Cone	Spent Caustic	1,007	1992
T-812	P-47	Cone	Spent Caustic	1,007	1992
T-814	P-49	Cone	Spent Caustic	1,007	1992

EUG 43 Storage Vessel T-813

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-813	P-48	Cone	Amine	1,007	1992

EUG 44 Process Vessel T-210001

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-210001	P-50	Cone	Polymer Asphalt	19	1996

EUG 45 Storage Vessel T-210002

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-210002	P-51	Cone	10 % H_3PO_4	9,517	1996

EUG 46 Storage Vessels T-210003 through T-210008

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-210003	P-52	Cone	Asphalt	3,021	1996
T-210004	P-52	Cone	Asphalt	6,526	1996
T-210005	P-52	Cone	Asphalt	6,526	1996
T-210006	P-52	Cone	Polymer Asphalt	10,197	1996
T-210007	P-52	Cone	Polymer Asphalt	10,197	1996
T-210008	P-52	Cone	Polymer Asphalt	11,715	2001

EUG 47 Storage Vessels T-100149 & T-100150

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-100149	P-53	Cone	Asphalt	35,847	1996
T-100150	P-54	Cone	Asphalt	35,847	1996

EUG 48 Sour Water Stripper Storage Vessel T-1152

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1152	P-55	External Floating	Sour Water	11,890	1999

EUG 49 Sour Water Stripper Storage Vessel T-83001

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-83001	P-184	Cone	Sour Water	18,885	1993

EUG 100 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-101	P-101	Process Heater	30.8	Mod. 1998

EUG 101 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-102B	P-102	Process Heater	135.0	Mod. 1998

EUG 102 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-102A	P-103	Process Heater	160.0	Mod. 1998

EUG 103 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-403	P-104	Process Heater	98.7	1980

EUG 104 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-404/5	P-105/6	Process Heater	99.3	Mod. 1980

EUG 106 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-406	P-107	Process Heater	28.0	1974

EUG 107 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-601	P-108	Process Heater	58.5	1975

EUG 109 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-901	P-110	Process Heater	60.0	1969

EUG 111 Process Heater for Storage Vessel T-1113

EU	Point	Description	MMBTUH	Const. Date
H-1013	P-112	2 Each Process Heaters	2.4, Each	1954

EUG 115 Process Flare (East)

EU	Point	Description	MMBTUH	Const. Date
Crude Unit Flare	P-116	Process Flare	27.0	1976

EUG 116 Asphalt Blowstill and Thermal Oxidizer

EU	Point	Description	Const. Date
HI-801	P-117	Asphalt Blowstill and Thermal Oxidizer	1992

EUG 117 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-103	P-118	Process Heater	102.6	1974

EUG 118 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-201	P-119	Process Heater	116.7	1974

EUG 119 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-301	P-120	Process Heater	21.6	1974

EUG 120 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-401A	P-121	Process Heater	16.0	1969

EUG 121 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-401B	P-122	Process Heater	14.8	1974

EUG 122 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-402A	P-123	Process Heater	13.9	1970

EUG 123 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-402B	P-124	Process Heater	15.8	1963

EUG 124 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-407	P-125	Process Heater	25.0	1974

EUG 125 Boiler

EU	Point	Description	MMBTUH	Const. Date
B-801	P-126	Boiler	72.5	1974

EUG 126 Boiler

EU	Point	Description	MMBTUH	Const. Date
B-802	P-127	Boiler	89.8	1975

EUG 127 Boiler

EU	Point	Description	MMBTUH	Const. Date
B-803	P-128	Boiler	86.8	1979

EUG 128 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-411	P-129	Process Heater	28.0	1986

EUG 134 Refinery Flare (West)

EU	Point	Description	MMBTUH	Const. Date
HI-81001	P-135	West Flare	28.0	1993

EUG 135 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-603	P-136	Process Heater	125.5	1992

EUG 136 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-6501	P-137	Process Heater	92.1	1992

EUG 137 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-6502	P-138	Process Heater	54.3	1992

EUG 138 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-15001	P-139	Process Heater	326.8	1992

EUG 139 Process Heater

EU	Point	Description	MMBTUH	Const. Date
H-210001	P-140	Process Heater	12.2	1996

EUG 140 Gasoline Loading Rack Vapor Combustor

EU	Point	Const. Date
Light Products Loading Terminal	P-141	1996

EUG 141[1] FCCU Flue Gas Scrubber

EU	Point	Description	Const. Date
FGS-200	P-142	FCCU No. 1 Regenerator/CO Boilers and FCCU No. 2 Regenerator	2004-5

[1] - EUG 141A, 141B, and 141C, are all vented to this EUG. EUG 145 will either be vented to this EUG or another wet scrubber.

EUG 141A FCCU No. 1 Regenerator and CO Boiler/Incinerator

EU	Point	Description	Const. Date
HI-251	P-142	FCCU No. 1 Regenerator	Mod. 1996

EUG 141B CO Boilers

EU	Point	Description	MMBTUH	Const. Date
B-253	P-142	CO Boiler	144.0	2004-5
B-254	P-142	Boiler/CO Boiler	144.0	2004-5

EUG 141C FCCU No. 2 Regenerator

EU	Point	Description	Const. Date
R-251	P-142	FCCU No. 2 Regenerator	Mod. 1996

EUG 142 #1 SRU Incinerator

EU	Point	Description	MMBTUH	Const. Date
HI-501	P-144	#1 SRU Incinerator	13.2	1995

EUG 143 Emergency Generators

EU	Point	Make/Model	KW	Serial #	Const. Date
EEQ-8801	P-145	DMT/DMT-825D2	750	93447-1	1994
EEQ-80001	P-146	Cummins/6BT5.9G-2	80	45555233	1997

EUG 144 Alternate Flares

EU	Point	Description	MMBTUH	Const. Date
altfl	P-147	Alternate Crude Unit Flare	27	< 1968
altfl	P-148	Alternate Alkylation Unit Flare	28	< 1968

EUG 145 FCCU Catalyst Hopper Vent

EU	Point	Description	Const. Date
cat_hop	P-149	FCCU Catalyst Hopper Vent	Mod. 1981

EUG 146 Platformer Catalyst Regeneration Vent

EU	Point	Description	Const. Date
CCR	P-150	Platformer Catalyst Regeneration Combustion Vent	1980

EUG 147 Instrument/Plant Air Compressor

EU	Point	Make/Model	hp	Serial #	Const. Date
C-80018	P-151	Detroit Diesel/8V-92TA	450	69102	1993

EUG 148 Asphalt Tank Heater

EU	Point	Description	MMBTUH	Const. Date
H-100024	P-152	Asphalt Tank Heater	13.5	1999

EUG 168 Storage Vessel T-1155

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1155	P-168	External Floating	Heavy Naphtha/Distillate	163,555	2003-4

EUG 169 Storage Vessel T-156

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-156	P-169	Cone	FCCU Slurry/Fuel Oil No. 6	56,000	2003-4

EUG 170 #2 SRU Incinerator

EU	Point	Description	MMBTUH	Const. Date
H-5601	P-170	SRU Incinerator	40.4	2004-5

EUG 171 Hot Oil Heater

EU	Point	Description	MMBTUH	Const. Date
H-5602	P-171	Hot Oil Heater	20.0	2004-5

EUG 172 Regenerated Amine Storage Vessel TK-5801

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-5801	P-172	Cone	Amine	895	2004-5

EUG 173 Liquid Sulfur Storage Vessel TK-5602

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-5602	P-171	Cone	Sulfur	3,644	2004-5

EUG 174 Molten Sulfur Railcar Loading Rack

EU	Point	Loading Rack	Loading Arm
LR-SB001	P-171	1	1
			2
			3

EUG 175 WWTP Incinerator

EU	Point	Description	MMBTUH	Const. Date
HI-8801	P-176	WWTP Incinerator	15.9	2004

EUG 176 #1 SRU Sulfur Storage Pit

EU	Point	Contents	Const. Date
SSP-520	SSP-520	Sulfur	1995

EUG 177 #1 SRU Molten Sulfur Railcar Loading Arm

EU	Point	Loading Rack	Loading Arm	Const. Date
MSLA-520	MSLA-520	1	1	1993

EUG 180 Co-Processor Heater

EU	Point	Description	MMBTUH	Const. Date
H-6701	P-180	Co-Processor Heater	11.8	2005-6

EUG 184 Emergency Alky-Deluge Water-Curtain Pumps Diesel Engines

EU	Point	Make/Model	HP	Const. Date
EWCP-1	P-185	Caterpillar 3412	800	2004
EWCP-2	P-186	Caterpillar 3412	800	2004
EWCP-3	P-187	Caterpillar 3412	800	2004

EUG 185 VOC Railcar Loading Station

EU	Point	Loading Rack	Loading Arm	Const. Date
RCALOAD 900	P-185	1	1	2004

EUG 186 LPG Loading Station

EU	Point	Loading Bays	Loading Arm
LPG	F-115	1	1
			2
			3
			4

EUG 200 Fugitive Equipment Leaks

EU	Number Items	Type of Equipment
FUGEL	18,145	Valves
	32,988	Connectors
	42	Compressor Seals
	594	Pump Seals
	465	Other

EUG 201 Wastewater Fugitive Equipment Leaks

EU	Number Items	Type of Equipment
WWFUG	470	Sewer Cups (P-Trap)
	26	Junction Boxes
	21	Miscellaneous

EUG 224 Asphalt and No. 6 Fuel Oil Railcar Loading

EU	Point	Loading Bays	Loading Arm
AsRail	F-124	2	1
			2
			3
			4
			5

EUG 225 Asphalt and No. 6 Fuel Oil Truck Loading

EU	Point	Loading Bays	Loading Arm
AsTruk	F-125	4	1
			2
			3
			4
			5
			6
			7

SECTION IV. EMISSIONS

The implementation of NSPS and OAC 252:100 new source review (NSR) standards in conjunction with PSD standards has resulted in a significant reduction of the emissions of criteria pollutants at the refinery. The quantification of these emissions and the assumptions utilized are discussed in detail in this section. Emissions from the facility were based on an extensive assessment of the modifications to the refinery, the applicable standards, and the equipment involved. Emission statements are not exactly conclusive in presentation; yet they represent the approximate quantification(s). As technology developed through the timeframe as provided, actual and potential emissions became dependent on updating emission factors in the absence of continuous monitoring systems. Historical emission estimates are not conclusive, or exact, yet are an estimate based on the attempt to quantify changes associated with modifications occurring within a time-frame as indicated to reflect upon the net emissions potential decreases established by NSPS, NSR, and BACT applications. This permit will supercede any conditions of the previous permits that affect the EU incorporated into this permit.

List of Affected Air Quality Permits

98-172-C (M-15) (PSD)*	98-172-C (M-18) (PSD)*	96-402-O (M-1)

* - This permit will incorporate all of the EU of these affected permits and these permits will become null and void upon commencement of construction.

VOC emissions from the VOC storage vessels are based on EPA TANKS 4.0 and the throughputs and vapor pressures on the following page.

Storage/Process Vessel VOC Emissions

EUG	Stg. Vess.	Contents	Throughput BPY	VP psia	Emissions TPY
1	T-1008	LCO Slurry	2,275,243	0.150	5.08
2	T-1018	NHT Charge	9,490,000	**2.800**	**0.52**
3	T-1019	Alkylate	2,555,000	RVP 15	14.30
4	T-153	FCCU Charge	10,950,222	0.002	1.75
6	T-1118	Asphalt	733,674	0.014	0.99
8	T-1135	PMA Asphalt	4,424	1.322	0.24
14	T-1082	Crude Oil	36,500,000	RVP 5	11.26
15	T-1083				
16	T-1084				
17	T-1085	Slurry/Fuel Oil #6	447,964	0.0002	0.01
19	T-1102	Asphalt	1,100,000	0.014	1.50
19	T-1151	Asphalt	1,893,114	0.014	2.56
20	T-1111	Asphalt	506,757	0.014	0.69
21	T-1113	Asphalt	1,200,548	0.014	1.62
22	T-1115	Gasoline	11,205,500	RVP 10.5	6.29
23	T-1116	Gasoline	9,510,400	RVP 10.5	6.29
24	T-1121	Diesel/Kerosene	1,190,974	0.008	0.63
26	T-1123	Gasoline	2,735,640	RVP 10.5	9.14
27	T-1124	Gasoline	4,920,856	RVP 10.5	9.66
28	T-1125	Gasoline	7,500,000	RVP 10.5	12.00
29	T-1126	Gasoline	7,500,000	RVP 10.5	12.00
30	T-1127	Diesel/Kerosene	3,300,000	0.008	1.56
31	T-1128	Diesel/Kerosene	3,300,000	0.008	1.56
32	T-1129	Diesel/Kerosene	61,264	0.008	0.03
33	T-1130	FCCU Gasoline	10,402,500	RVP 15	26.76
34	T-1131	FCCU Gasoline	12,514,286	11.00	9.24
35	T-1132	Reformate	12,514,286	11.00	7.83
36	T-1141	Diesel/Kerosene	3,578,477	0.080	1.91
37	T-1142	Diesel/Kerosene	2,391,914	0.080	1.27
39	V-815	Wastewater Fallout	73,000	0.130	0.51
40	V-818	Slop Oil	70,832	0.010	0.01
41	V-8801	Wastewater	9,560,914	RVP 4.5	7.34
41	V-8802	Wastewater	9,560,914	RVP 4.5	7.34
44	T-210001	PMA Mix	2,800,000	0.041	1.92
46	T-210003	Asphalt Flux	1,398,970	0.041	1.33
46	T-210004	PMA Rxn	2,100,000	0.041	2.24
46	T-210005	PMA Rxn	2,100,000	0.041	2.24
46	T-210006	PMA	1,400,000	0.041	2.21
46	T-210007	PMA	1,400,000	0.041	2.21
46	T-210008	PMA	1,400,000	0.041	2.44
47	T-100149	Asphalt Flux	1,400,000	0.135	1.77
47	T-100150	Asphalt Base	2,800,000	0.135	2.08
48	T-1152	Sour Water	2,131,286	0.349	0.31
49	T-83001	Sour Water	2,565,575	0.010	4.79
168	T-1155	Naphtha	12,045,000	1.322	3.13
169	T-156	FCCU Slurry	442,319	0.028	0.98
	TOTALS				**189.54**

The tables below show the estimated potential emissions for the process heaters and boilers and assumes 100% conversion of H_2S in the fuel gas to SO_2.

Emissions from Heaters (Without Low-NO_X Burners)

	NO_X		CO		PM_{10}		SO_2		VOC	
Heaters	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-101	3.02	13.23	2.54	11.11	0.23	1.01	1.03	4.53	0.17	0.73
H-403	9.68	42.38	8.13	35.60	0.74	3.22	3.31	14.51	0.53	2.33
H-404/5	9.74	42.64	8.18	35.82	0.74	3.24	3.34	14.61	0.54	2.35
H-406	2.75	12.02	2.31	10.10	0.21	0.91	0.93	4.12	0.15	0.66
H-601	5.74	25.12	4.82	21.10	0.44	1.91	1.96	8.60	0.32	1.38
H-901	5.88	25.76	4.94	21.64	0.45	1.96	2.01	8.82	0.32	1.42
H-1013	0.47	2.06	0.40	1.73	0.04	0.16	0.16	0.71	0.03	0.11
H-103	19.11	83.71	8.45	37.01	0.76	3.35	3.44	15.08	0.55	2.42
H-201	21.74	95.21	9.61	42.09	0.87	3.81	3.92	17.16	0.63	2.76
H-301	2.12	9.28	1.78	7.79	0.16	0.71	0.73	3.18	0.12	0.51
H-401A	1.57	6.87	1.32	5.77	0.12	0.52	0.54	2.35	0.09	0.38
H-401B	1.45	6.36	1.22	5.34	0.11	0.48	0.50	2.18	0.08	0.35
H-402A	1.36	5.97	1.15	5.01	0.10	0.45	0.47	2.04	0.08	0.33
H-402B	1.55	6.79	1.30	5.70	0.12	0.52	0.53	2.32	0.09	0.37
H-407	2.45	10.74	2.06	9.02	0.19	0.82	0.84	3.68	0.13	0.59
H-411	2.75	12.02	2.31	10.10	0.21	0.91	0.92	4.05	0.15	0.66
H-210001	1.20	5.24	1.00	4.40	0.09	0.40	0.08	0.35	0.07	0.29
H-100024	0.68	2.96	1.11	4.87	0.10	0.44	0.45	1.98	0.07	0.32
Totals	**93.26**	**408.4**	**62.63**	**274.2**	**5.68**	**24.82**	**25.16**	**110.3**	**4.12**	**17.96**

Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X, CO, PM_{10}, & VOC - AP-42, Section 1.4 (7/98); for heaters rated greater than 100 MMBTUH (H-103 and H-201) the uncontrolled post-NSPS NO_X emission factors are used; and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU); For H-210001, a fuel-gas H_2S concentration of 0.025 grains/DSCF and a HHV of 1,020 BTU/SCF (0.0066 lb/MMBTU) was used.

Emissions from Boilers (Without Low-NO_X Burners)

	NO_X		CO		PM_{10}		SO_2		VOC	
Boilers	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
B-801	7.11	31.13	5.97	26.15	0.54	2.37	2.43	10.66	0.39	1.71
B-802	8.80	38.56	7.40	32.39	0.67	2.93	3.01	13.20	0.48	2.12
B-803	8.51	37.27	7.15	31.31	0.65	2.83	2.91	12.76	0.47	2.05
Totals	**24.42**	**107.0**	**20.52**	**89.9**	**1.86**	**8.13**	**8.35**	**36.62**	**1.34**	**5.88**

Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X, CO, PM_{10}, & VOC - AP-42, Section 1.4 (7/98); and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

Emissions from Heaters (With Low-NO_X Burners)

	NO_X		CO		PM_{10}		SO_2		VOC	
Heaters	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-102A	7.20	31.54	13.18	57.71	1.75	8.51	5.37	23.52	0.86	3.78
H-102B	7.97	34.90	11.12	48.70	1.64	7.19	4.53	19.85	0.73	3.19
H-603	8.28	36.28	5.21	22.81	0.94	4.10	4.21	18.45	0.68	2.96
H-6501	5.53	24.20	3.72	16.29	0.69	3.01	3.09	13.54	0.50	2.18
H-6502	3.26	14.27	2.19	9.61	0.41	1.77	1.82	7.98	0.29	1.28
H-15001	19.61	85.88	9.80	42.94	2.44	10.67	10.97	48.05	1.76	7.72
H-5602	0.98	4.29	1.65	7.21	0.15	0.65	0.67	2.94	0.11	0.47
H-6701	0.71	3.10	0.97	4.26	0.09	0.39	0.40	1.74	0.06	0.28
Totals	**53.54**	**234.5**	**47.84**	**209.5**	**8.11**	**36.29**	**31.06**	**136.1**	**4.99**	**21.86**

Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X emissions are based on the following: H-102A - 0.045 lb/MMBTU, H-102B - 0.059 lb/MMBTU, H-603 - 0.066 lb/MMBTU, H-6501, H-6502, H-15001, and H-6701 - 0.06 lb/MMBTU, and H-5602 - 0.050 lb/MMBTU.

CO - AP-42, Section 1.4 (7/98); except for H-603, H-6501, H-6502, and H-15001 which are based on the following: 0.0415, 0.0404, 0.0404, and 0.03 lb/MMBTU, respectively;

PM_{10}, & VOC - AP-42, Section 1.4 (7/98);

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

Emissions from the Diesel-Fired Engines

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-80018	13.95	27.90	3.01	6.01	0.99	1.98	0.18	0.36	1.13	2.26
EEQ-8801	28.80	11.52	7.65	3.06	0.52	0.21	0.45	0.18	0.74	0.29
EEQ-80001	9.16	3.66	1.97	0.79	0.64	0.26	0.10	0.04	0.75	0.30
EWCP-1	19.20	0.54	4.40	0.12	0.56	0.02	0.32	0.01	0.51	0.01
EWCP-2	19.20	0.54	4.40	0.12	0.56	0.02	0.32	0.01	0.51	0.01
EWCP-3	19.20	0.54	4.40	0.12	0.56	0.02	0.32	0.01	0.51	0.01
Totals	**109.5**	**44.70**	**25.83**	**10.22**	**3.83**	**2.51**	**1.69**	**0.61**	**4.15**	**2.88**

Emissions from the diesel fired engines are based on the following operating hours and ratings: C-80018 - 4,000 hours and 450-hp; EEQ-8801 - 800 hours and 9.00 MMBTUH; EEQ-80001 - 800 hours and 2.08 MMBTUH; and EWCP-1 through 3 - 56 hours and 4.69 MMBTUH; and the following emission factors:

NO_X, CO, & PM_{10}, VOC - AP-42, Section 3.3, (10/96) for C-80018 and EEQ-80001 and AP-42, Section 3.4, (10/96) for EEQ-8801 and EWCP-1 through EWCP-3; and

SO_2 - AP-42, Section 3.4, (10/96) and a maximum sulfur content of 0.05% by weight;

Emissions from the Flares

	NO_X		CO		PM_{10}		SO_2		VOC	
Point	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
P-116	1.84	8.04	9.99	43.76	0.25	1.10	0.91	3.97	3.78	16.56
P-135	1.90	8.34	10.36	45.38	0.21	0.91	0.94	4.12	3.92	17.17
P-147	1.84	8.04	9.99	43.76	0.25	1.10	0.91	3.97	3.78	16.56
P-148	1.90	8.34	10.36	45.38	0.21	0.91	0.94	4.12	3.92	17.17
Totals	**7.48**	**32.76**	**40.70**	**178.3**	**0.92**	**4.02**	**3.70**	**16.18**	**15.40**	**67.46**

Emissions from the Crude Unit Flare (East Flare - P-116), Platformer/Alkylation Unit Flare (West Flare - P-135), and the two alternative flares (P-147 and P-148) are based a heat rating of 27 MMBTUH for the crude unit flare and it's alternative flare and a heat rating of 28 MMBTUH for the Platformer/Alkylation Unit Flare and it's alternative and the following:

NO_X, CO, & VOC - AP-42, Section 13.5 (1/95);
PM_{10} - AP-42, Section 1.4 (7/98); and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

Emissions from the Gasoline and Diesel Loading Dock Vapor Incinerator

	NO_X		CO		PM_{10}		SO_2		VOC	
Point	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
P-141	5.20	15.79	13.00	39.48	----	----	0.01	0.01	30.16	73.66

VOC emissions from the vapor combustor are based on loading 22,525,714 bbl/yr and 155,782 gal/hr of gasoline and diesel, a limit of 10 mg VOC/L gasoline loaded, and a collection efficiency of 99.2%. Annual loading losses were based on loading 22,525,714 bbl/yr of gasoline, AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a vapor pressure (vp) of 5.8 psia, a temperature of 60 °F, a vapor molecular weight of 65, and a 99.2% collection efficiency. Hourly loading losses were based on loading 155,782 gallons per hour (gph) of gasoline, AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a maximum vp of 9.4 psia, a maximum temperature of 93 °F, a vapor molecular weight of 65, and a 99.2% collection efficiency. NO_X, CO, and SO_2 emissions from the vapor combustor are based on the following emission factors:

NO_X - 4 mg/L of gasoline loaded (0.03338 lb/Mgal);
CO - 10 mg/L of gasoline loaded (0.08345 lb/Mgal); and
SO_2 - Combustion of 2,000 gallons of distillate fuel oil and a factor of 7.1 lb/Mgal.

Emissions from the Catalyst Hopper's Wet Scrubber

	PM_{10}	
Point	**lb/hr**	**TPY**
P-149	0.46	2.01

Potential emissions from the catalyst hoppers are based on the flow rate and factors for spent and fresh catalyst. Emissions due to spent catalyst are based on a continuous catalyst recirculation rate of approximately 1,050 Tons/hr through two hoppers and an emission factor of 0.01 lbs PM/ton (AP-42, Section 11.24 (1/95), Table 11.24.2, high moisture ore, material handling and transfer - all minerals except bauxite); and emissions due to fresh catalyst are based on a continuous catalyst recirculation rate of 13 tons/hr, an emission factor of 0.12 lbs PM/ton (AP-42, Section 11.24 (1/95), Table 11.24.2, low moisture ore, material handling and transfer - all minerals except bauxite), and continuous operation. PM_{10} emissions for the high moisture ore are 40% of PM emissions. PM_{10} emissions for the low moisture ore are 50% of PM emissions. The high moisture ore factor was utilized for the spent catalyst since live steam is injected to control emissions of PM. The emissions from the catalyst hoppers are vented to a cyclone with an efficiency of 70% for PM and 50% for PM_{10}. The cyclones are vented to a wet scrubber with an efficiency of 93.3% for PM and 90% for PM_{10}.

Emissions from the Reformer CCR

	NO_X		CO		PM_{10}		SO_2		VOC	
Point	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
P-150	1.19	5.21	0.44	1.93	0.56	2.46	0.67	2.91	0.05	0.20

Emissions are based on a coke-burning rate of 70 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 1,000 lb/hr and a coke generation rate of 7% of the catalyst weight, with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion. PM_{10} emissions also include a recovery factor for the catalyst of 99.99%.

NO_X - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom);
CO - a concentration of 500 ppmv @ 0% O_2 and a flow rate of 200 DSCFM;
PM_{10} - 13.2 lb/ton of coke combusted (Spreader Stoker); 0.46 lb/hr combustion & 0.10 lb/hr catalyst;
SO_2 - 38 x (Sulfur Content) lb/ton of coke combusted (Spreader Stoker); and
VOC - 1.3 lb/ton of coke combusted (Underfeed Stoker).

	Uncontrolled		**Controlled**	
	lb/hr	**TPY**	**lb/hr**	**TPY**
HCl Emissions	10.10	44.23	0.30	1.33

Ethylene dichloride ($C_2H_4Cl_2$) or perchloroethylene ($Cl_2C:CCl_2$) is injected into the reformer and then discharged as hydrogen chloride (HCl). The facility is required to comply with the MACT (97% control of HCl from the CCR or 10 ppmv HCl @ 3% O_2). Ethylene dichloride or perchloroethylene is almost completely destroyed by reaction with the catalyst and air. Estimated material usage is based on 0.0106 lb of perchloroethylene per barrel with the CCR running at 26 MBPD. Potential HCl emissions are based on 100% of the chloride being converted to HCl and being emitted from the CCR. Emissions of HCl from the CCR after control are estimated using the required control efficiency of 97%. The controls for HCl will also help reduce PM_{10} emissions by approximately 95%.

Emissions from the #2 SRU Incinerator H-5601

	NO_X		CO		PM_{10}		SO_2		VOC	
Point	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
P-170	3.96	17.35	3.33	14.57	0.30	1.32	26.2	114.7	0.2	1.0

Emissions from the incinerator are based on combustion of 27.7 MMBTUH of auxiliary fuel, combustion of 552,396 SCFH of waste gas with a heat content of 23 BTU/SCF, and the following:

NO_X, CO, PM10, VOC - AP-42, Section 1.4 (7/98); and
SO_2 - NSPS, Subpart J, SO_2 emission limit of 250 ppmdv and a flow rate of 630,000 DSCFH @ 0% O_2.

Emissions from the #2 Molten Sulfur Railcar Loading Rack

	H_2S	
EU	**lb/hr**	**TPY**
LR-SB001	0.57	2.48

Emissions from the molten sulfur railcar loading rack are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), a loading rate of 100,000 lb/hr of molten sulfur per railcar, three loading stations, and the density of molten sulfur (124.8 lb/CF).

Emissions from the WWTP Incinerator H-8801

	NO_X		CO		PM_{10}		SO_2		VOC	
Point	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
P-176	8.87	38.87	1.31	5.74	0.12	0.52	5.82	25.49	2.18	9.56

Emissions from the WWTP Incinerator are based on the following:

NO_X - a maximum concentration of 315 ppmv NH_3 in the bioreactor off-gases, a waste gas flow rate of 198,000 SCFH, and a 95.0% combustion efficiency plus an emission factor of 0.12 lb/MMBTU and a heat rate of 15 MMBTUH;

CO & PM_{10} - a heat rate of 15.9 MMBTUH, and AP-42, Section 1.4 (7/98);

SO_2 - a maximum concentration of 0.1 grain/DSCF H_2S in the bioreactor off-gases, a flow rate of 198,000 SCFH, a 95.0% combustion efficiency and an auxiliary fuel flow rate of 15 MMTBUH @ 800 BTU/SCF HHV; and

VOC - a waste gas flow rate of 42.05 lb/hr and a combustion efficiency of 95% and a heat rate of 15 MMBTUH and AP-42, Section 1.4 (7/98).

Emissions from the #1 SRU Sulfur Storage Pit, Railcar Loading of Sulfur, and Storage Vessel TK-5602

	H_2S	
EU	**lb/hr**	**TPY**
SSP-520	0.07	0.29
MSLA-520	0.57	2.48
TK-5602	0.07	0.30

These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2. Potential emissions are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), the density of molten sulfur (124.8 lb/CF) and the following:

SSP-520 - the run-down rate of molten sulfur (125 LTD);

MSLA-520 - a loading rate of 100,000 lb/hr of molten sulfur per railcar, one loading station; and

TK-5602 - the run-down rate of 12,100 lb/hr of molten sulfur (130 LTD).

Emissions from VOC Railcar Loading Station

	NO_X		CO		VOC		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**lb/hr**	**TPY**	**TPY**	**lb/hr**	**TPY**
RCALOAD900	0.10	0.12	0.54	0.63	1.10	1.29	0.01	0.01

Potential emissions are based on a short-term throughput of 220 gallons per minute, an annual throughput of 733,505 bbl/yr, and the following:

NO_X & CO - the emission factors from AP-42, Section 13.5 (1/95), and a heat rating of 130,000 BTU/gallon;

VOC - the allowable emission factor from NESHAP, Subpart R of 10 mg/L (0.0835 lb/1,000 gallon).

The railcar loading station will be vented through the asphalt blowstill and will be added to the emission limits for the asphalt blowstill thermal oxidizer.

VOC Emissions from the LPG Loading Operations

	Throughput	Emissions
Station (EU)	**BPY**	**TPY**
Railcar Loading (LPG)	857,513	14.7
Tank Truck Loading (LPG)	599,603	13.3
Unloading (LPG)	642,515	6.5

Potential VOC emissions from LPG loading are based on an emission factor of 3.74 lb VOC/disconnect except for loading of propane into tank trucks where a factor of 13.5 lb/disconnect was used.

Fugitive Equipment Leak Emissions

Fugitive VOC emissions are based on the factors below derived from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), and an estimated number of components.

VOC Emissions from Fugitive Equipment Leaks

Number Items	Type of Equipment	Factor (kg/hr/source)	Emissions (TPY)
18,145	Valves	0.00221[1]	387.22
102	Pressure Relief Valves[2]	0.16000	3.15
76	Pressure Relief Valves	0.16000	117.42
259	Connectors	0.00025	0.63
32,729	Flanges	0.00025	79.01
42	Compressor Seals[2]	0.63600	5.16
594	Pump Seals	0.01385	79.44
465	Other	0.00865	38.84
Total			710.87

[1] – This factor is equivalent to an overall control efficiency for valves of approximately 62 to 70% from the average refinery emissions factors.

[2] – Potential emissions are controlled at 98%.

Wastewater Fugitive Equipment Leaks

Emissions from wastewater fugitive equipment leaks were estimated based on the number of equipment items multiplied by a standard emission factor (0.032 kg/hr/source) and are estimated at 154.3 TPY. Implementation of Title 40 CFR Part 60, Subpart QQQ, reduces emissions to a certain degree, but the extent is minute compared to the end-of-line release from aerated biological reactors. The effectiveness of Subpart QQQ provides a greater reduction of VOC emissions when implemented in conjunction with Title 40 CFR Part 61, Subpart FF.

VOC Emissions from the Asphalt and Gas-Oil/Slurry/#6 Fuel Oil Railcar & Truck Loading

	Throughput	Emissions
Loading Station (EU)	**BPY**	**TPY**
Railcar Loading (AsRail)	4,745,000	16.68
Tank Truck Loading (AsTruck)	191,625	0.01

The emissions are based on AP-42 (1/95), Section 5.2 and the listed throughputs.

Emissions from the Existing SRU Netting Project

Actuals Pre-mod.[1]	**TPY NO_X**	**TPY CO**	**TPY PM_{10}**	**TPY SO_2**	**TPY VOC**	**TPY H_2S**
H-501[2]	10.16	5.69	0.73	7.59	0.37	0.05
H-801 Blowstill Gases[3]	5.34	4.49	0.79	13.60	0.29	0.27
H-801 SWS Gases[4]	340.90	----	41.49	1,478.83	----	29.57
H-801 Auxiliary Fuel[5]	3.59	19.51	0.39	1.64	7.38	0.02
H-602[6]	9.01	7.57	0.69	2.85	0.50	0.03
HI-81001[7]	10.91	59.37	1.20	1.81	22.46	0.02
Wastewater[8]	----	----	----	----	14.10	0.85
Railcar Loading[9]	----	----	----	----	----	0.11
Sulfur Storage Pit[10]	----	----	----	----	----	0.11
Sub-Total	**379.91**	**96.63**	**45.29**	**1,506.32**	**45.10**	**31.03**
PTE Post-mod.						
H-501[11]	8.50	4.76	1.88	52.47	0.31	0.31
HI-801 Blowstill[12]	41.05	22.47	3.84	35.03	1.47	0.37
H-603[13]	36.28	22.80	4.10	18.45	2.96	0.18
H-6501[14]	24.20	16.29	3.01	13.54	2.18	0.13
H-6502[15]	14.27	9.61	1.77	7.98	1.28	0.08
H-15001[16]	85.88	42.94	10.67	48.05	7.72	0.46
HI-81001[17]	8.34	45.38	0.91	4.12	17.17	0.04
T-83001[18]	----	----	----	----	4.79	----
Added Fugitives[19]	----	----	----	2.60	12.33	0.33
Wastewater[20]	----	----	----	----	17.09	9.07
Railcar Loading[21]	----	----	----	----	----	2.54
Sulfur Storage Pit[22]	----	----	----	----	----	0.29
Sub-Total	**218.52**	**164.25**	**25.32**	**182.24**	**67.30**	**13.80**
Net Change	**-161.39**	**67.62**	**-19.97**	**-1,324.08**	**22.20**	**-17.23**

1 Emissions represent actual average emissions from 1989 and 1990.

2 Existing emissions from the SRU incinerator are based on the following:

NO_X, CO, PM_{10}, VOC - For emissions from combustion of the auxiliary fuel, emissions were based on an average fuel usage of 143.5 MMSCFY, a heat content of 867 BTU/SCF (HHV), the emission factor from AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 68,099 SCFH of waste gas, a heat content of 23 BTU/SCF, the emission factor from AP-42, Section 1.4 (7/98), and an adjustment factor of 1.5; NO_X emissions include a safety factor of 1.5 and PM_{10} emissions have been adjusted for emissions of H_2SO_4; and

SO_2 - Based on an average concentration of 50 ppmdv and a flow rate of 210,296 DSCFH @ 0% O_2; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4.

3 Actual emissions from combustion of the asphalt blowstill gases are based on a flow rate of approximately 308 SCF/bbl and an average production rate of 5359.5 bbl/day and the following:

NO_X, CO, VOC, & PM_{10} - AP-42, Section 1.4 (7/98); NO_X emissions include a safety factor of 1.5 and PM_{10} emissions have been adjusted for emissions of H_2SO_4; and

SO_2 - an average concentration of 282 ppmw H_2S in the blowstill gases and 96.34% combustion efficiency; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4.

[4] Actual emissions from combustion of the sour water stripper gases are based on a water flow rate of 121.6 gpm, a gas flow rate of 3.86 SCF/gallon, and the following:

NO_X - an average concentration of 1,178 ppmw NH_3 in the sour water, 100% collection efficiency, and 63.85% combustion efficiency with approximately 37.31% being converted to NO_2 and 26.83% being converted to N_2O emissions;

CO & VOC - no emissions were calculated and are considered insignificant;

PM_{10} - emissions of PM have been adjusted for emissions of H_2SO_4; and

SO_2 - an average concentration of 3,117 ppmw H_2S in the sour water, 100% collection efficiency, and 96.34% combustion efficiency; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4.

[5] Emissions from combustion of the auxiliary fuel in the blowstill are based on an average fuel usage of 121.6 MMSCFY, a heating value of 867 BTU/SCF, and the following:

NO_X, CO, PM_{10}, & VOC - AP-42, Section 1.4 (7/98); NO_X emissions include a safety factor of 1.5; and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF.

[6] Emissions from H-602 are based on an average fuel usage of 212.0 MMSCFY, a heating value of 867 BTU/SCF, and the following:

NO_X, CO, PM_{10}, & VOC - AP-42, Section 1.4 (7/98); and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF.

[7] Emissions from the flare are based on an average auxiliary fuel usage of 135.0 MMSCFY, a heating value of 2,377 BTU/SCF, and the following:

NO_X, CO, & VOC - AP-42, Section 13.5 (1/95);

PM_{10} - AP-42, Section 1.4 (7/98);

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF.

[8] Actual emissions for wastewater operations are based on a component counts and the WATER9 program.

[9] Actual emissions from the sulfur railcar loading operations are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), an annual average production rate of 49 LTD, and the density of molten sulfur (124.8 lb/SCF).

[10] Actual emissions for the sulfur storage pit are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), an annual average production rate of 49 LTD, and the density of molten sulfur (124.8 lb/CF).

[11] Potential emissions from the SRU incinerator are based on the following:

NO_X, CO, PM_{10}, VOC - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 8.2 MMBTUH and the emission factor from AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 217,512 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); NO_X emissions include a safety factor of 1.5 and PM_{10} emissions have been adjusted for emissions of H_2SO_4;

SO_2 - Based on the NSPS, Subpart J, SO_2 emission limit of 250 ppmdv and a flow rate of 288,212 DSCFH @ 0% O_2; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4;

[12] Potential emissions from the Asphalt Blowstill are based on the following:

NO_X - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH and the emission factor from AP-42, Section 1.4 (7/98) multiplied by 1.5; for emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a heat content of 2,363 BTU/lb, and the emission factor from AP-42, Section 1.4 (7/98) multiplied by 1.5; for emissions from nitrogen in the waste gas (as NO_2), emissions were based on a concentration of 6.2 ppmdv and a flow rate of 282,823 SCFH.

CO & VOC, & PM_{10} - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH and AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a heat rating of 2,363 BTU/lb, and AP-42, Section 1.4 (7/98); emissions of PM_{10} have been adjusted for emissions of H_2SO_4; and

SO_2 - A refinery fuel-gas H_2S concentration of 0.1 grain/DSCF, a flow rate of 0.016 MMSCFH of auxiliary fuel, and a flow rate of 0.283 MMSCFH of waste gas; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4;

[13] Emissions from heater H-603 are based on a heat input rating of 125.5 MMBTUH and the following:
NO_X - Mfg. data - 0.066 lb/MMBTU;
CO - Stack tests & performance data - 42.3 lb/MMSCF;
PM_{10} & VOC - AP-42, Section 1.4 (7/98); and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

[14] Emissions from heater H-6501 are based on a heat input rating of 92.1 MMBTUH and the following:
NO_X - Mfg. data - 0.0600 lb/MMBTU;
CO - Stack tests & performance data - 0.0404 lb/MMBTU;
PM_{10} & VOC - AP-42, Section 1.4 (7/98); and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

[15] Emissions from heater H-6502 are based on a heat input rating of 54.3 MMBTUH and the following:
NO_X - Mfg. data - 0.0600 lb/MMBTU;
CO - Stack tests & performance data - 0.0404 lb/MMBTU;
PM_{10} & VOC - AP-42, Section 1.4 (7/98); and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

[16] Emissions from heater H-15001 are based on a heat input rating of 326.8 MMBTUH and the following:
NO_X - Mfg. data - 0.06 lb/MMBTU;
CO - Stack tests & performance data – 0.030 lb/MMSCF;
PM_{10} & VOC - AP-42, Section 1.4 (7/98); and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

[17] Emissions from the West Flare HI-81001 are based on a heat input rating of 28 MMBTUH and the following:
NO_X, CO, & VOC - AP-42, Section 13.5 (1/95);
PM_{10} - AP-42, Section 1.4 (7/98); and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

[18] Emissions from T-83001 are based on TANKS4.0 a throughput of 2,565,575 bbl/yr and a vapor pressure of 0.10 psia.

[19] Actual and potential emissions for fugitive equipment leaks are the same due to the fact that they are based only on equipment counts. Therefore, only added fugitive equipment emissions are reviewed for inclusion in the netting analysis.

[20] Potential emissions for wastewater operations are based on a component counts and the WATER9 program.

[21] Potential emissions from the sulfur railcar loading operations are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), a loading rate of 100,000 lb/hr of molten sulfur per railcar, one loading station, and the density of molten sulfur (124.8 lb/CF).

[22] Potential emissions for sulfur storage pit are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), the run-down rate of 11,458 lb/hr of molten sulfur (125 LTD), and the density of molten sulfur (124.8 lb/CF).

Emissions from the FCCU as Evaluated in the BACT Submittal

The table below shows the emissions as they were evaluated in the proposed and accepted BACT submittal. The baseline emissions and the proposed BACT limits do not include the FCCU feedstock pre-heater.

	TPY NO_X	TPY CO	TPY PM_{10}	TPY SO_2
Baseline Emissions[1]	473.1	229.1	466.4	2,024.7
BACT Emission Limits[2]	356.8	182.7	46.6	202.4
Emission Reductions	**116.3**	**46.4**	**419.8**	**1,822.3**

[1] Baseline emissions for the FCCU are based on the following:

NO_X Emissions:

NO_X emissions from the FCCU No. 1 Regenerator were based on stack test results (65.34 lb/hr) conducted on January 22-23, 1998, and extrapolated from a feedstock rate of 25,836 bbl/day to 30,000 bbl/day. NO_X emissions from the FCCU No. 2 Regenerator were based on stack test results (27.69 lb/hr) conducted on January 22-23, 1998, and extrapolated from a feedstock rate of 25,836 bbl/day to 30,000 bbl/day.

CO Emissions:

CO emissions from the FCCU No. 1 Regenerator were based on an average of stack test results (89.28, 16.96, 26.49 lb/hr) conducted on January 22-23, 1998, August 9, 1999, and August 12, 1999, and extrapolated from feedstock rates of 25,836, and 22,050, 26,322 bbl/day, respectively, to 30,000 bbl/day. CO emissions from the FCCU No. 2 Regenerator were based on the detection limit for CO based on stack test results conducted on January 22-23, 1998.

PM_{10} Emissions:

PM_{10} emissions from the FCCU No. 1 Regenerator were based on stack test results (52.56 lb/hr) conducted on August 12 1999, and extrapolated from a feedstock rate of 26,322 bbl/day to 30,000 bbl/day. PM_{10} emissions from the FCCU No. 2 Regenerator were based on stack test results (40.87 lb/hr) conducted on August 12, 1999, and extrapolated from a feedstock rate of 26,322 bbl/day to 30,000 bbl/day.

SO_2 Emissions:

SO_2 emissions from the FCCU No. 1 Regenerator were based on stack test results (246.18 lb/hr) conducted on January 22-23, 1998, and extrapolated from a feedstock rate of 25,836 bbl/day and a feedstock sulfur content of 0.2733% by weight to 30,000 bbl/day and a feedstock sulfur content of 0.3% by weight. NO_X emissions from the FCCU No. 2 Regenerator were based on stack test results (112.35 lb/hr), which was conducted on August 12, 1999, extrapolated from a feedstock rate of 26,322 bbl/day and a feedstock sulfur content of 0.2587% by weight to 30,000 bbl/day and a feedstock sulfur content of 0.3% by weight.

[2] BACT emission limits for the FCCU are based on the following:

NO_X Emissions:

NO_X emissions from the FCCU No. 1 Regenerator were based on a 35% reduction of baseline emissions. NO_X emissions from the FCCU No. 2 Regenerator were based on the baseline emission estimates.

CO Emissions:

CO emissions from the FCCU No. 1 Regenerator were based on a flow rate of 46,018 SCFM and a concentration of 175 ppmdv @ 0% O_2. CO emissions from the FCCU No. 2 Regenerator were based on 30,221 SCFM and a concentration of 50 ppmdv @ 0% O_2. The total reductions are approximately 20% of the baseline emissions.

PM_{10} Emissions:

PM_{10} emissions from the FCCU No. 1 and No. 2 Regenerators were based on a 90% reduction of baseline emissions (front-half).

SO_2 Emissions:

SO_2 emissions from the FCCU No. 1 and No. 2 Regenerators were based on a 90% reduction of baseline emissions.

Emissions from the FCCU After Application of CO Boiler SEP

The table below shows the emissions as the emissions from the FCCU after application of the proposed and accepted supplemental environmental project of replacing the existing FCCU No. 1 Regenerator CO Boiler/Incinerator with a larger CO Boiler that would be able to handle the total flow of the FCCU No. 1 Regenerator. The existing CO Boiler and Incinerator will be removed from service.

	TPY NO_X	TPY CO	TPY PM_{10}	TPY SO_2
BACT Emission Limits	356.8	182.7	46.6	202.4
SEP Emission Estimates[1]	307.0	182.7	46.6	202.4
Emission Reductions	**49.8**	**0.0**	**0.0**	**0.0**

[1] SEP emissions estimates remain the same as the BACT emission limits for the FCCU, except for NO_X emissions, which are based on an additional 15% reduction of the FCCU No. 1 BACT emission limits. NO_X emissions from the FCCU No. 2 Regenerator remained the same.

Emissions From The New Boiler/CO Boiler Project

The new boiler/CO boiler (B-254) will be equipped with ULNB (0.06 lb NO_X/MMBTUH). The primary design basis for the boiler is firing 100% refinery fuel-gas. The secondary design basis is firing all of the FCCU No. 1 Regenerator flue-gas in combination with refinery fuel-gas. The table below summarizes emissions for criteria pollutants for the CO boiler operation. The emissions shown below only represent the emissions arising from operation of the boiler itself and not the criteria pollutant emissions processed through the boiler. The existing CO boiler will be removed from service.

NO_X		CO		PM_{10}		SO_2		VOC	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
8.64	37.84	11.86	51.94	1.07	4.70	4.84	21.19	0.78	3.40

Emissions are based on a heat input rating of 144 MMBTUH and the following:

NO_X - manufacturers guarantee of 0.06 lb/MMBTU;

CO, VOC, & PM_{10} - AP-42, Section 1.4 (7/98); and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

Allowable Emissions from the FCCU

NO_X		CO		PM_{10}		SO_2		VOC	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
118.0	344.8	178.1	234.7	22.37	51.34	66.44	223.6	0.78	3.40

Allowable emissions are the combination of the BACT allowables plus the new Boiler/CO Boiler allowables.

Facility Wide Emissions Prior to Modifications

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
T-1018	----	----	----	----	----	----	----	----	2.78	12.17
T-1019	----	----	----	----	----	----	----	----	5.50	24.08
T-1115	----	----	----	----	----	----	----	----	0.83	9.98
T-1116	----	----	----	----	----	----	----	----	0.83	9.97
T-1130	----	----	----	----	----	----	----	----	6.11	26.76
H-102B[1]	25.15	110.1	11.12	48.70	1.01	4.41	4.52	19.81	0.73	3.19
H-102A[1]	27.01	118.3	11.94	52.30	1.08	4.73	4.86	21.28	0.78	3.42
H-403	9.68	42.38	8.13	35.60	0.74	3.22	3.32	14.53	0.53	2.33
H-404	4.76	20.83	3.99	17.49	0.36	1.58	1.63	7.14	0.26	1.15
H-405	4.98	21.81	4.18	18.32	0.38	1.66	1.71	7.48	0.27	1.20
H-406	2.75	12.02	2.31	10.10	0.21	0.91	0.94	4.12	0.15	0.66
CU Flare	1.84	8.04	9.99	43.76	0.25	1.10	34.14	149.5	3.78	16.56
HI-801[2]	35.09	153.7	0.61	2.68	0.01	0.38	205.5	899.9	0.05	0.21
H-201	8.22	35.99	6.90	30.23	0.62	2.74	2.82	12.33	0.45	1.98
H-401A	1.57	6.87	1.32	5.77	0.12	0.52	0.54	2.35	0.09	0.38
H-401B	1.45	6.36	1.22	5.34	0.11	0.48	0.50	2.18	0.08	0.35
H-402A	1.36	5.97	1.15	5.01	0.10	0.45	0.47	2.05	0.08	0.33
H-402B	1.55	6.79	1.30	5.70	0.12	0.52	0.53	2.33	0.09	0.37
H-407	2.45	10.74	2.06	9.02	0.19	0.82	0.84	3.68	0.13	0.59
B-802	8.80	38.56	7.40	32.39	0.67	2.93	3.02	13.21	0.48	2.12
B-803	8.51	37.27	7.15	31.31	0.65	2.83	2.92	12.77	0.47	2.05
HI-81001[2]	1.90	8.34	10.36	45.38	0.21	0.87	0.94	4.12	3.92	17.17
H-15001[2]	10.85	47.53	8.80	38.54	1.32	5.78	3.80	16.63	0.80	3.51
LPLT	----	----	----	----	----	----	----	----	90.41	396.0
HI-251[1]	75.87	332.3	52.31	229.1	52.56	230.2	313.8	1,374	----	Neg.
R-251[1]	32.15	140.8	----	Neg.	40.87	179.1	140.4	650.4	----	Neg.
H-501[2]	1.22	5.36	0.17	0.75	0.01	0.16	7.81	34.20	0.03	0.14
EEQ8801[3]	28.80	11.52	7.65	3.06	0.52	0.21	0.45	0.18	0.74	0.29
EEQ80001[3]	9.16	3.66	1.97	0.79	0.64	0.26	0.10	0.04	0.75	0.30
Cat_Hop[1]	----	----	----	----	9.18	40.20	----	----	----	----
CCR[4]	0.83	3.65	0.12	0.54	0.39	1.73	0.47	2.04	0.03	0.14
C-80018[5]	13.95	27.90	3.01	6.01	0.99	1.98	0.18	0.36	1.13	2.26
H-100024[6]	0.68	2.96	1.11	4.87	0.10	0.44	0.45	1.98	0.07	0.32
ASU	----	----	----	----	----	----	----	----	5.46	16.90
Area 100	----	----	----	----	----	----	----	----	176.0	771.0
Area 250	----	----	----	----	----	----	----	----	28.78	126.0
Area 300	----	----	----	----	----	----	----	----	35.78	156.7
Area 400	----	----	----	----	----	----	----	----	77.40	339.0
Area 500	----	----	----	----	----	----	0.98	4.31	3.25	14.24
Area 900	----	----	----	----	----	----	----	----	33.26	145.7
WW-500	----	----	----	----	----	----	----	----	3.22	14.10
TOTALS	**320.58**	**1,219.8**	**166.27**	**682.76**	**113.41**	**490.21**	**737.64**	**3,262.9**	**485.50**	**2,123.6**

[1] - Based on emissions from the BACT analysis.
[2] - Based on emissions from Permit No. 95-506-O (M-1).
[3] - Based on emissions from Permit No. 97-523-O.
[4] - Based on emissions from Permit No. 98-265-O.
[5] - Based on emissions from Permit No. 98-229-O.
[6] - Based on emissions from Permit No. 98-172-C.

Total Facility Wide Emissions After Modifications

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Stg. Vess.	----	----	----	----	----	----	----	----	43.27	189.54
Heaters1	93.26	408.4	62.63	274.2	5.68	24.82	25.16	110.3	4.12	17.96
Boilers	24.42	106.96	20.52	89.9	1.86	8.13	8.35	36.62	1.34	5.88
Heaters2	53.54	234.5	47.84	209.5	8.11	36.29	31.06	136.1	4.99	21.86
Engines	109.5	44.70	25.83	10.22	3.83	2.51	1.69	0.61	4.15	2.88
Flares	7.48	32.76	40.70	178.28	0.92	4.02	3.70	16.18	15.40	67.46
HI-801	9.37	41.05	5.13	22.47	0.88	3.84	8.00	35.03	0.34	1.47
LPLT	5.20	15.79	13.00	39.48	----	----	0.01	0.01	30.16	73.66
FGS-200	118.00	344.83	178.13	234.67	22.37	51.34	66.44	223.59	0.78	3.40
H-501	1.94	8.50	1.09	4.76	0.43	1.88	11.98	52.47	0.07	0.31
Cat_Hop	----	----	----	----	3.77	1.88	----	----	----	----
CCR	1.19	5.21	0.44	1.93	0.56	2.46	0.67	2.91	0.05	0.20
H-5601	3.96	17.35	3.33	14.57	0.30	1.32	26.19	114.71	0.22	0.95
HI-8801	8.87	38.87	1.31	5.74	0.12	0.52	5.82	25.49	2.18	9.56
LPG	----	----	----	----	----	----	----	----	----	34.50
Fugitives	----	----	----	----	----	----	----	----	----	710.87
WW Fug.	----	----	----	----	----	----	----	----	----	154.30
TOTALS	**436.73**	**1,298.9**	**399.95**	**1,085.7**	**48.83**	**139.01**	**189.07**	**754.02**	**107.07**	**1,294.8**

SECTION V. PSD REVIEW

Over the years, TPI Petroleum, Inc. (TPI) has implemented numerous projects to improve the product quality and throughput at the Valero Ardmore Refinery. Based on the compliance analysis in Permit No. 98-172-C (M-15) (PSD), TPI identified several historical modifications, which resulted in emissions increases that triggered PSD requirements. Therefore, the requirements of the PSD program were addressed for each of the modifications in Permit No. 98-172-C (M-15) (PSD). Only projects for which there was a physical equipment modification were considered in the BACT analysis. For this permit, the facility requested modification of some of the emission limits from the previous BACT determinations. The following modifications and associated pollutants are the ones with the requested changes that were subject to full PSD analysis including BACT:

Facility Modification	**Pollutants Subject to PSD review**
FCCU No. 1 Regenerator and CO Boiler/Incinerator	CO
FCCU No. 2 Regenerator	CO

The existing refinery was among the industries defined as a PSD-major source at an emissions level of 100 TPY. Full PSD review of emissions consisted of the following:

- a determination of BACT;
- an evaluation of existing air quality and a determination concerning monitoring requirements;

- an evaluation of PSD increment consumption;
- an analysis of compliance with National Ambient Air Quality Standards (NAAQS);
- an evaluation of source-related impacts on growth, soils, vegetation, and visibility;
- and a Class I area impact evaluation.

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, the change in mobile source emissions was negligible. The facility was an existing facility. Few, if any, new employees were added. The added equipment required a small amount of maintenance traffic. The vast majority of the feedstock for the plant arrived by pipeline rather than by vehicle. Existing mobile source emissions have been treated as background emissions.

A. Best Available Control Technology

A BACT analysis was required for all pollutants emitted above PSD-significance levels for each of the modifications. BACT is generally defined as "an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any…source…which on a case-by-case basis is determined to be achievable taking into account energy, environmental, and economic impacts and other costs." A "top-down" analysis is the preferred method for determining BACT. The five basic steps of the top-down procedure are:

Step 1. Identify all control technologies
Step 2. Eliminate technically infeasible options
Step 3. Rank remaining control technologies by control effectiveness
Step 4. Evaluate most effective controls and document results
Step 5. Select BACT

The EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

The BACT analysis evaluates control technologies/techniques for the following pollutants emitted from the sources identified above:

- CO emissions from the FCCU two-stage regenerator.

All proposed and applied BACT must meet, at minimum, all applicable NSPS and NESHAP. In some cases, technologies not sufficiently effective by themselves can be used in tandem to achieve BACT emission reduction levels.

The BACT analysis was originally submitted on December 28, 1998. It was later updated by a submittal on April 21, 2000, by Environmental Resources Management (ERM). This BACT analysis was accepted as submitted and was incorporated into Consent Order No. 02-007. The updated application was submitted on July 23, 2002. The BACT analysis in this permit memorandum was based on and contains information from the analysis provided by ERM. Based on the BACT analysis the table below summarizes the BACT selected for the sources previously identified.

Selected BACT

Source	**PSD Trigger Pollutant**	**Selected BACT**
FCCU No. 1 Regenerator & CO Boiler/Incinerator	CO	Thermal Oxidation
FCCU No. 2 Regenerator	CO	High Temperature Regeneration

<u>FCCU Regenerators</u>

The FCCU consists of the riser, the reactor, a two stage regenerator system, air blowers, spent catalyst stripper, catalyst recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. The FCCU regenerator at the TPI Ardmore refinery operates in two stages. The first regenerator stage operates in an oxygen deficient, partial burn mode. The second stage regenerator is a full-burn, or high temperature regeneration, operation.

The FCCU regenerator at the Ardmore refinery is subject to NSPS, Subpart J. The applicable NSPS maximum allowable emissions from a FCCU regenerator are listed below:

NSPS Limits For FCCU Regenerators

Pollutant	**Emission Limit**	**Reference**
CO	500 ppmdv	40 CER 60.103(a)

The resources consulted in the compilation of potential options for CO control for the Ardmore refinery FCCU include the following:

- EPA's New Source Review Website
- The Maximum Achievable Control Technology (MACT) floor analysis included in the preamble to the proposed Part 63 Subpart UUU - NESHAP from Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units and Sulfur Plants
- U.S. EPA's RBLC database
- Texas Natural Resource Conservation Commission (TNRCC) FCCU BACT guidance
- South Coast Air Quality Management District (SCAQMD) FCCU BACT guidelines
- Control technology vendors
- Technical books and articles
- Other refineries with similar process limits

Additionally, the environmental agencies for Illinois, Indiana, Ohio, Michigan, Wisconsin, Arkansas, Oklahoma, New Mexico, and Louisiana were surveyed for guidance on BACT for FCCUs. All of these agencies indicated that they rely on the RBLC database as a basis for review of proposed BACT and that all determinations are made on a case-by-case basis. None of these states have any definitive BACT requirements or guidance for FCCUs.

FCCU No. 1 Regenerator and Thermal Oxidation System

CO

Carbon monoxide generation in the FCCU regenerator occurs from the incomplete thermal oxidation of carbon on the spent catalyst. Because the oxidation of CO to carbon dioxide (CO_2) generates significantly more heat than that of carbon (C) to CO, refiners typically operate regenerators under partial burn to maintain temperatures of the FCCU within the design specifications. TPI's FCCU No. 1 Regenerator is operated in partial burn to effect better control for FCCU temperatures than is practical from controlling fuel and oxygen feeds. The NSPS limit for CO is 500 ppmvd. Listed below are all the available control technologies for control of CO from the FCCU No. 1 Regenerator. A brief description of the control technologies is also given. The refinery currently uses a combination of a CO Boiler and a CO Incinerator as baseline controls on the FCCU No. 1 Regenerator. The boiler and incinerator are operated in parallel to one another and share a common stack. The 1998 stack test data indicates an average flue gas CO concentration of 308 ppmdv. This scenario is proposed as BACT for the FCCU No. 1 Regenerator.

1) Identification of All Available Control Technologies

- Catalytic Oxidation
- Thermal Oxidation
- High-Temperature Regeneration
- Combustion Promoter

Catalytic Oxidation
In catalytic oxidation, a catalyst enables the oxidation reaction to occur at much lower temperatures and at shorter residence times than in thermal oxidation. These conditions reduce operating costs, enable a smaller-sized system than thermal oxidation (incineration), and reduce construction material requirements. The most efficient catalysts are precious metals dispersed on high surface area washcoats that are bonded to ceramic honeycomb blocks. These catalysts are designed to operate between 600 °F to 1,200 °F and operating pressures up to 300 psig. Catalytic oxidation systems typically destroy 95% to 99% of CO and VOCs.

Thermal Oxidation (CO Boiler or CO Incinerator)
Thermal oxidation uses the concepts of temperature, time, and turbulence to achieve complete combustion. The combustion process is thought of as occurring in two separate stages: (1) the combustion of fuels, and (2) the combustion of pollutants. Use of a thermal oxidizer is equivalent to adding a combustion chamber where the regenerator vent gas is heated above its

ignition temperature. Excess oxygen and additional fuel are supplied to reach this higher temperature and complete the conversion of CO to CO_2.

Partial burn FCCU regenerators operate at or below 1,250 °F. The lower operating temperatures result in regenerator vent gas CO concentrations well in excess of 500 ppmdv. Once the vent gases pass through the thermal oxidizer, CO concentrations are comparable with those of a high temperature regeneration FCCU. For refiners operating a high temperature regeneration FCCU, a thermal oxidizer is not required because effluent CO concentrations are already less than 500 ppmdv.

There are two types of thermal oxidizers currently used to control CO emissions from a partial burn FCCU regenerator, CO boilers and CO incinerators. CO boilers typically operate at approximately 1,800 °F to ensure complete conversion. CO incinerators typically operate between 1,600 and 2,000 °F. A CO boiler has an advantage over an incinerator in that the boiler also offers heat recovery for purposes of steam generation.

A thermal oxidizer has the disadvantage of being an additional combustion source. This increased fuel combustion, along with the high oxidizer operating temperatures, significantly increases the thermal NO_X emissions from the unit. It should be noted that the RBLC does not indicate the use of CO incinerators to meet BACT requirements for CO control. However, this may be due to an industry preference for the heat recovery capabilities that CO boilers offer.

<u>High Temperature Regeneration</u>

High temperature regeneration, or full combustion regeneration, uses excess oxygen and high operating temperatures, 1,300 to 1,400 °F, to reduce carbon deposits, or coke, on the FCCU catalyst and to complete the conversion of CO to carbon dioxide (CO_2). CO concentrations in high temperature regenerator effluents are usually 50 to 500 ppmdv. Partial burn regenerators operate at approximately 1,250 °F with effluent CO concentrations in excess of 1,000 ppmdv.

High temperature regeneration has some disadvantages. The unit must run at a lower catalyst/oil ratio because of the higher regenerator temperatures. There is an increased requirement for combustion oxygen and regenerators operating at maximum capacity may not be able to handle the increased air demand without upgrading the regenerator blower or installing an oxygen injection system. Also, for regenerators built prior to 1974, the higher operating temperatures may require more expensive metallurgy so as not to exceed the temperature rating of the regenerator internals.

<u>CO Combustion Promoter</u>

Combustion promoter is an additive injected into the circulating catalyst on an as-needed basis primarily to control regenerator afterburn and increase combustion efficiency. As a secondary benefit, combustion promoters slightly increase CO oxidation, thereby potentially reducing CO emissions from the regenerator under certain conditions. The promoter is an alumina or silica-alumina powder typically impregnated with platinum and/or palladium to catalyze the oxidation of CO to CO_2. Because the Ardmore Refinery regenerators control CO emissions to below NSPS levels by either thermal oxidation or full combustion, combustion promoter is not currently used.

2) Eliminate Technically Infeasible Control Technologies

<u>Catalytic Oxidation</u>
The primary problem with catalytic oxidizers is the loss of catalyst activity. They cannot be used on waste gas streams containing significant amounts of PM. PM deposits foul the catalyst and prohibit oxidation. Based on stack testing and expected FCCU upset conditions, the PM emission rate from the FCCU regeneration unit is such that it is considered technically infeasible to install a catalytic oxidation unit for control of CO emissions.

Though an upstream control device could significantly reduce the amount of PM that routinely passes through a catalytic oxidizer, the unit would still be susceptible to damaging PM concentrations during an FCCU "reversal" which is an upset condition where large quantities of catalyst are emitted. The infeasibility of catalytic oxidation for control of CO from FCCU regenerators was supported by a search of the RBLC Database. The RBLC Database contains no record of catalytic oxidation being successfully used as a CO control for FCCU regenerators, despite the fact that several of the RBLC entries did employ either an ESP or a WS for particulate control. The applicant also contacted equipment vendors and other state agencies who supported the position that catalytic oxidation is not applicable to FCCU regenerators.

<u>High Temperature Regeneration</u>
High temperature regeneration is not a feasible control option for the FCCU No. 1 Regenerator because in the two-regenerator system, the first regenerator is designed to operate in a wet, low temperature environment. Catalyst structure breaks down under high temperature and high moisture conditions, while its structure is protected if the temperature is kept relatively low in a high moisture environment. The second regenerator in the two-regenerator system is designed to operate at high temperature conditions, because the first regenerator has already removed the moisture.

The nature of the two-regenerator system favors high-temperature regeneration in the second regenerator, but prevents its implementation in the first regenerator. High temperature regeneration is not a feasible control technology for the FCCU No. 1 Regenerator.

3) Rank Remaining Control Technologies

Potential CO Control Technologies

Control Technology	**Estimated Control Efficiency**
Thermal Oxidation	> 95%
Combustion Promoter	Undetermined*

* - This technology is considered an augmentation technology and not necessarily a sufficient technology by itself.

4) Evaluate Remaining Control Technologies and Document Results

Thermal Oxidation (CO Boiler or CO Incinerator)
The most effective feasible control technology, thermal oxidation, is proposed as BACT for the FCCU No. 1 Regenerator. In 1985, TPI installed a boiler and a thermal incinerator to control CO emissions from the FCCU No. 1 Regenerator off-gas. The existing CO Boiler is a thermal oxidizer that converts the CO to CO_2 by combusting the stream with refinery fuel gas at 1,300 to 1,400 ^oF for about 1.6 to 2.2 seconds. Although a CO Boiler is currently used for the FCCU No. 1 Regenerator, it is not adequately sized to handle the entire flue gas stream during typical operation. As a result, a thermal incinerator is operated in parallel to the CO Boiler to handle the excess flow. The incinerator typically converts the CO to CO_2 with refinery fuel gas at approximately 1,400 ^oF for about 2 to 3 seconds. The CO Boiler and Incinerator emissions are vented through a common stack. Historically, the CO Boiler and Incinerator combination have been operated to maximize the steam production from the boiler rather than to achieve a CO emission rate lower than that required by NSPS. Consequently, there was a theoretical possibility that a new CO Boiler designed to handle the entire flue gas flow from the FCCU No. 1 Regenerator could provide greater reduction in CO than the existing system. A vendor quote and emission rate guarantee for a new unit was obtained for comparison to the existing system.

Recent CEMS data from the existing system indicate that it can be operated to achieve the guaranteed emission rate of a new, larger CO boiler. Therefore, the vendor guarantee for a new CO boiler was used only as a benchmark to indicate that the existing system can achieve emission levels comparable to a new thermal oxidation system. Reliance on this data does not imply that a new CO boiler must be used for CO control from the FCCU No.1 Regenerator but that the existing system can be used to achieve BACT.

It should also be noted that a new CO boiler would not be economically justified for control of CO from the FCCU No. 1 Regenerator. The annualized cost per ton of CO removed in comparison to the baseline would be $7,628. Even when the economic benefit of additional steam production is taken into account, the annualized cost per ton of $5,898 is clearly higher than the cost per ton of CO removed typically considered justified by a permitting agency. Because a new CO boiler is not economically justified, and because the existing thermal oxidation system can achieve comparable levels of CO control, the baseline CO control using the existing CO boiler and incinerator system is proposed as BACT.

Since there are no solid or liquid waste streams from the CO Boiler, there are no additional adverse environmental impacts to consider. Furthermore, a CO Boiler allows the flue gas from the FCCU No. 1 Regenerator to be used for steam production, thus having positive economic and energy impacts.

CO Combustion Promoter
While use of a combustion promoter can lower the CO content of the flue gas, it also has some drawbacks. The promoter has to be frequently added to the regenerator, two to three times a day, at a rate of 3 to 5 lb/ton of fresh FCCU catalyst. It increases the requirement for combustion air

and raises the regenerator temperature; thus, increasing thermal deactivation of the catalyst. Finally, the use of CO combustion promoters can marginally increase NO_X emissions.

Use of CO promoters is not always technically feasible. For regenerators with vent gas CO concentrations already below 500 ppmdv, refiners typically will not see appreciable reductions in CO emissions. Use of a CO combustion promoter to control CO emissions from the two stage regenerator at the TPI Ardmore facility is questionable. The first stage is designed to operate as a partial burn stage in an oxygen lean environment. Use of a CO combustion promoter requires excess oxygen and higher operating temperature than are available in the partial burn first stage. The flue gas from this first stage is already routed to a CO Boiler and Incinerator. If the combustion promoter were to decrease the CO concentration of the flue gas fed to the existing CO Boiler, this would mean an increase in supplemental fuel usage, which would cause an increase in thermal NO_X formation from the CO Boiler, since combustion of CO lowers the adiabatic flame temperature. An increase in NO_X formation and additional fuel requirements are an unacceptable compromise to control CO emissions from the first regenerator stage.

The second stage of the regenerator is a full burn stage and CO concentrations in the flue gas from this stage are already negligible. Therefore, use of a CO combustion promoter will offer no measurable reduction in CO emissions from the refinery's FCCU.

<u>Combined Control Technologies</u>
High temperature regeneration is already in use on the FCCU No. 2 Regenerator, and is not feasible on the FCCU No. 1 Regenerator. Combustion promoter would provide little if any additional CO removal to either regenerator. The FCCU No. 2 Regenerator already typically reduces CO levels to below detection limits. The existing thermal oxidation system would not reduce CO to lower levels with the addition of combustion promoter.

5) Select BACT

The baseline case of thermal oxidation is acceptable as BACT for the FCCU No. 1 Regenerator. Thermal oxidation is the feasible control technology having the highest control efficiency, and can achieve an emission level of 50 ppmv CO. Both the RBLC and communication with vendors by the applicant indicate that CO boilers and incinerators have been used successfully at refineries for CO control from FCCU regenerators.

While the upper range of the theoretical control efficiency for catalytic oxidation is slightly higher than for the baseline case, it is not appropriate for use at the Ardmore Refinery primarily due to the particulate loading from the FCCU regenerator. The BACT analysis indicates that thermal oxidation is the most effective control device that is both commercially available and appropriate for the source.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
CO	CO Boiler	153.9* tons/year	CO continuous emission monitoring systems (CEMS). Compute 12-month rolling total CO emissions using monthly average CO concentration monitored along with monthly average H_2O concentration, and monthly average stack gas flow rate.

* - All CO emissions from the FCCU No. 1 Regeneration unit are combined with the FCCU No. 2 Regeneration unit. This number only represents the portion of CO contributed by the FCCU No. 1 Regenerator system.

FCCU No. 2 Regenerator

Since all of the pollutants and related control technologies for the FCCU No. 1 Regenerator and the FCCU No. 2 Regenerator are the same, all of the determinations for the FCCU No. 2 Regenerator will start from the eliminated technically infeasible control techniques.

CO

1) Eliminate Technically Infeasible Control Technologies

Catalytic Oxidation

SCR is considered a technically infeasible option for CO control for the FCCU No. 2 Regenerator for the same reasons it was determined infeasible for the FCCU No. 1 Regenerator.

2) Rank Remaining Control Technologies

Potential CO Control Technologies

Control Technology	Estimated Control Efficiency
High Temperature Regeneration	> 95%
Combustion Promoter	Undetermined*

* - This technology is considered an augmentation technology and not necessarily a sufficient technology by itself.

3) Evaluate Remaining Control Technologies and Document Results

High Temperature Regeneration
The FCCU No. 2 Regenerator uses high temperature regeneration to oxidize CO. The FCCU No. 2 Regenerator is extraordinarily efficient at oxidizing CO. In a January 1998 stack test, CO was measured in three runs, two of which did not report CO in detectable levels, the other reported a concentration of 0.04 ppmv. Because high temperature regeneration is extremely efficient for removal of CO from the FCCU No. 2 Regenerator, replacement of, or addition to high temperature regeneration is not warranted for CO control.

CO Combustion Promoter
Use of CO promoters is not always technically feasible. For regenerators with vent gas CO concentrations already below 500 ppmdv, refiners typically will not see appreciable reductions in CO emissions. The FCCU No. 2 Regenerator is a full burn regenerator and CO concentrations in the flue gas from this stage are already negligible. Therefore, use of a CO combustion promoter will offer no measurable reduction in CO emissions from the refinery's FCCU.

Combined Control Technologies
High temperature regeneration is already in use on the No. 2 regenerator. Combustion promoter would provide little if any additional CO removal. The No. 2 regenerator already typically reduces CO levels to below detection limits. The existing thermal oxidation system would not reduce CO to lower levels with the addition of combustion promoter.

4) Select BACT

The baseline case of high temperature regeneration is acceptable as BACT for the FCCU No. 2 Regenerator.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits (12-month rolling total)	Proposed Monitoring
CO	High Temperature Regeneration	28.9* tons/year	CO continuous emission monitoring systems (CEMS). Compute 12-month rolling total CO emissions using monthly average CO concentration monitored along with monthly average H_2O concentration, and monthly average stack gas flow rate.

* - All CO emissions from the FCCU No. 2 Regeneration unit are combined with the FCCU No. 1 Regeneration unit. This number only represents the portion of CO contributed by the FCCU No. 2 Regenerator.

B. Air Quality Impacts

The Valero Ardmore Refinery is located in Carter County, which is currently designated attainment or unclassified for all criteria pollutants, and there are no areas classified as non-attainment within 50 kilometers of the refinery. This modification will result in emission increases sufficient to trigger the Prevention of Significant Deterioration (PSD) requirements codified in 40 CFR Part 52.

Prevention of Significant Deterioration (PSD) is a construction-permitting program designed to ensure air quality does not degrade beyond the NAAQS or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels (MSL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the MLS, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area.

Valero has prepared an air quality analysis in accordance with the procedures and methodology presented, which are consistent with guidance provided by the Oklahoma Department of Environmental Quality (ODEQ) and Environmental Protection Agency (EPA). The results of this air quality analysis show that the proposed emissions authorized in this permit will not cause or contribute to an exceedance of the NAAQS or significant PSD increment consumption.

Modeling Methodology

The refined air quality modeling analyses for the Valero Ardmore Refinery employed USEPA's Industrial Source Complex (ISC3) (Version 02035) model (USEPA, 1995a). The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474). The regulatory default option was selected such that USEPA guideline requirements were met.

The stack height regulations promulgated by USEPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;
H = Height of the controlling structure on which the source is located, or nearby structure; and
L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 mile (0.8 km) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985).

The heights of some of the exhaust stacks at the refinery were evaluated to determine if they are less than respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the ISC3 model.

In October 1993, USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions. The BPIP program was used to determine the wind direction-dependent building dimensions for input to the ISC3 model.

The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures that has the greatest influence ($H + 1.5\ L_b$) is selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 L_b downwind, 2 L_b upwind, and 0.5 L_b crosswind. These criteria are based on recommendations by USEPA. The building cavity effects were then used in the modeling analysis for the refinery. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5 L_b$$

where:

h_c = GEP stack height;
H = Height of the controlling structure on which the source is located, or nearby structure; and
L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts.

The meteorological data used in the dispersion modeling analyses consisted of five years (1986, 1987, 1988, 1990, and 1991) of hourly surface observations from the Oklahoma City, Oklahoma, National Weather Service Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991).

Surface observations consist of hourly measurements of wind direction, wind speed, temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. Based on NWS records, the anemometer height at the Oklahoma City station during this period was 6.1 meters.

Prior to use in the modeling analysis, the meteorological data sets were downloaded from the USEPA Support Center for Regulatory Air Models (SCRAM) website. This data was scanned for missing data, but no missing data was found. USEPA procedures outlined in the USEPA document, "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models," were used to fill gaps of information for single missing days. For larger periods of two or more missing days, seasonal averages were used to fill in the missing periods. The USEPA developed rural and urban interpolation methods to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights representative of the area in the vicinity of the refinery.

The urban/rural classification is used to determine which dispersion parameter to use in the model. Determination of the applicability of urban or rural dispersion is based upon land use or population density. For the land use method the source is circumscribed by a three kilometer radius circle, and uses within that radius analyzed to determine whether heavy and light industrial, commercial, and common and compact residential, comprise greater than 50 percent of the defined area. If so, then urban dispersion coefficients should be used. The land use in the area of the proposed facility is not comprised of greater than 50 percent of the above land use types and is considered a rural area.

The refined modeling used a nested Cartesian grid. Receptors were placed no greater than 50 meters apart along the boundary. From the fenceline, a 100-meter grid of receptors extended out to 1,000 meters. A 500-meter grid extended beyond this grid, out to 2.5 kilometers from the site. A 1,000-meter grid extended beyond this grid, out to 10 kilometers from the site. Beyond that, a spacing of 2.5 kilometers was used extending out to 50 kilometers from the facility. This modeling was used to define the radius of significant impact for each pollutant. All receptors were modeled with actual terrain data. The terrain data was taken from United States Geologic Survey (USGS) 7.5-minute Digital Elevation Model Files.

Summary of Modeling Emission Inventory

For each modeling analysis type (e.g., Preliminary Analysis, NAAQS or PSD Increment) varying modeling emission inventories were developed (e.g. contemporaneous increases, increases over baseline, or total emissions). However, the stack parameters for point sources in each inventory were modeled using actual stack parameters, with the exception of some psuedo-point type sources (e.g., storage vessels), that were modeled to represent their non-buoyant, low velocity type emissions. A discussion of the sources included in each modeling analysis is presented below.

Preliminary Analysis

Typically for PSD Preliminary Analyses, contemporaneous changes (i.e., changes within three years of the triggering event) in emissions are modeled. However, an evaluation of historic changes at the Refinery in the review, and issuance, of 98-172-C (PSD), effective January 2003, revealed that changes at the facility that occurred as early as 1982 and required permitting under PSD regulations. The contemporaneous changes of emissions modeled for Permit No. 98-172-C (PSD) included all other changes at the facility. For the purpose of this review and the AOI, only the added sources for this project were modeled.

On-Property Sources – Full Impact Analyses

Available air permitting and emissions inventory documentation was reviewed to identify on-property sources. For the NAAQS analyses, the identified on-property sources were modeled at their proposed allowable emission rates. For the PSD Increment analyses, the identified on-property sources were modeled at their increment-consuming emission rate. The increment-consuming emission rate was estimated by subtracting the historical two-year average emission rate from the proposed allowable emission rate. The on-property source emission inventories for the Full Impact Analyses were provided in the application.

Off-Property Sources – Full Impact Analyses

Off-property sources located within a radius defined by the AOI plus 50 kilometers were included in the Full Impact PSD Increment and NAAQS Analyses that were triggered by the Preliminary Analysis. An ODEQ database retrieval, ODEQ emission inventory reports, and ODEQ permitting files were used to identify applicable sources to be included in the modeling analyses and their respective stack parameters and emission rates. Off-property sources were assumed to be increment consuming and allowable emission rates were included in the model.

Due to its proximity to the Refinery (contiguous to the south), sources at Atlas were evaluated to assess whether they were increment-consuming sources or whether they were existing emission sources prior to the minor source baseline date. Information from Atlas permit applications was used to assess construction, reconstruction, and modification dates for Atlas' emission sources. A summary of the analysis that was used to evaluate the sources included in the PSD Increment Analysis and a summary of the off-property modeling emission inventories for the impact analyses (PSD Increment and NAAQS) were provided in the application.

<u>Preliminary Analysis</u>

The first step in the PSD modeling analysis was the Preliminary Analysis (AOI analysis). In this analysis net emission increases were modeled to evaluate whether the resultant highest predicted concentrations for each pollutant averaging period combination were of regulatory significance.

These results were also used to evaluate the extent of the modeling analysis that would be required. The results of the Preliminary Analysis were used to evaluate whether a Full Impact Analysis was required to define the resultant AOI for modeling purposes, and to evaluate whether a full analysis would be required. The results of the Preliminary Analysis are summarized below.

Preliminary Analysis Results

Pollutant	Averaging Period	Max. Predicted Concentration ($\mu g/m^3$)	PSD MSL ($\mu g/m^3$)	AOI (km)	Monitoring Exemption Levels ($\mu g/m^3$)
NO_2	Annual	3.0	1	3.0	14
CO	1-hour	378.6	2,000	N/A	N/A
	8-hour	112.9	500	N/A	575

The results predicted ambient CO concentrations to be less than the MSL for the both the 1-hour and 8-hour averaging periods. Thus a Full Impact Analysis was not required for CO (1-hour or 8-hour). The predicted ambient concentrations for NO_2 (annual) were greater than the MSL. Since regulatory-significant concentrations were predicted for NO_2 for the applicable averaging periods, a Full Impact Analysis was performed.

Full Impact Analysis (PSD Increment and NAAQS)

A Full Impact Analysis was performed to predict ambient concentrations for comparison to the NAAQS and PSD increment. This modeling analysis addressed emissions from the Valero Refinery's sources and off-property sources within the radius defined by the AOI plus 50 kilometers. The highest annual concentrations were evaluated for the long-term analyses.

If the modeling results predicted an exceedance of a standard, the receptor-averaging period for each predicted exceedance was compared to the significant receptor file created in the Preliminary Analysis to evaluate whether the Valero Refinery was predicted to be significant for the receptor averaging period combination at which the exceedance was predicted. If the predicted concentrations for the Valero Refinery were not significant for a receptor averaging period combination when an exceedance was predicted, the Valero Refinery was not considered to be contributing to the exceedance. The reported concentration was then identified using the significant receptor-averaging period combination with the highest predicted concentrations in the full analysis.

<u>Air Quality Monitoring Data</u>

The preliminary modeling conducted as part of this analysis resulted in predicted concentrations that were above the modeling significance levels for NO_2 (annual). Background concentration data was obtained from the ODEQ, Air Quality Division for NO_2. Since pre-construction monitoring is not possible for a retroactive PSD permit and pre-construction monitoring would only delay installation of control equipment, Air Quality allowed the use of monitoring data collected from the Ponca City Area. Ponca City and Ardmore are of a similar size and have similar source impacts. The monitoring data should provide conservative background data for the NAAQS analysis and are shown below. The background concentrations were added to the modeled results to demonstrate compliance with the NAAQS.

Summary of Background Concentrations

Pollutant	Averaging Period	Monitored Concentration (μg/m^3)
NO_2	Annual	13.2

<u>PSD NAAQS Full Impact Analyses</u>

This section provides the results of the PSD NAAQS Analyses.

NO_2 NAAQS Analysis

A summary of the annual NO_2 NAAQS modeling analysis is provided below.

NO_2 NAAQS Analysis Results

Averaging Period	NAAQS (μg/m^3)	Background (μg/m^3)	Max. Predicted Concentration (μg/m^3)	Predicted Conc. & Background (μg/m^3)
Annual	100	13.2	28.7	41.9

The highest predicted ambient concentration plus background was less than the NAAQS. Thus, no further analysis was required for the NO_2 NAAQS.

<u>PSD Increment Analysis</u>

This section provides the results of the PSD Increment Analysis.

NO_2 PSD Increment Analysis

A summary of the annual NO_2 PSD Increment Analysis is provided below.

NO_2 Increment Analysis Results

Averaging Period	Maximum Predicted Conc. (μg/m^3)	PSD Increment (μg/m^3)
Annual	3.9	25

The highest predicted ambient concentration plus background was less than the PSD increment. Thus, no further analysis was required for the annual NO_2 PSD increment.

Summary of Modeling Results

Pollutant	Analysis	Averaging Period	Standard ($\mu g/m^3$)	Ambient Impact ($\mu g/m^3$)[1]
NO_2	NAAQS	Annual	100	41.9
	Increment	Annual	25	3.9

[1] - Ambient Impacts include background concentrations.

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, & Visibility

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. The number of employees needed beyond those currently employed is insignificant.

Growth Impacts

The purpose of the growth impact analysis is to quantify the possible net growth of the population of the area as a direct result of the project. This growth can be measured by the increase in residents of the area, the additional use and need of commercial and industrial facilities to assist the additional population with everyday services, and other growth, such as additional sewage treatment discharges or motor vehicle emissions.

Approximately 50 trade jobs (i.e., welders, electricians, construction workers, etc.) over a 24 month period will be needed to complete the construction of the project. It is anticipated that the majority of these jobs will be local hires, thus not requiring any additional residential or commercial capacity within the area. No full-time positions are expected. There should be no increase in community growth or the need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary emissions associated with non-project related activities or growth.

Ambient Air Quality Impact Analysis

The purpose of this aspect of impact analysis is to predict the air quality in the area of the project during construction and after commencing operation. This analysis follows the growth analysis by combining the associated growth with the emissions from the proposed project and the emissions from other permitted sources in the area to predict the estimated total ground-level concentrations of pollutants as a result of the project, including construction.

The only source of additional emissions may be from fugitive dust generated from equipment transportation or vehicles during construction. Any long-term air quality impact in the area will result from emissions increases due to operation of the facility. These impacts have been analyzed in preceding sections.

Soils and Vegetation Impact

The primary soil units in the area of the Refinery are Amber very fine sandy loam and Dale silt loam. The main crops typically grown on the soils identified within the area of interest are native grasses, and cultivated crops. No sensitive aspects of the soil and vegetation in this area have been identified. As such, the secondary NAAQS, which establish ambient concentration levels below which it is anticipated that no harmful effects to either soil or vegetation can be expected, are used as the benchmark for this analysis.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. The modeling conducted, which demonstrated compliance with the Primary NAAQS simultaneously demonstrated compliance with the Secondary NAAQS because the Secondary NAAQS are higher or equal to the Primary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated.

Visibility Impairment

The area near the facility is primarily agricultural, consisting of pastureland. Some residences are located southeast and east of the facility. The closest airport is located approximately 3 miles north-northeast of the facility. Therefore, there are no airports, scenic vistas, or other areas that would be affected by minor reductions in visibility. The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. The project is actually expected to reduce visibility impacts of the existing facility. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

G. Class I Area Impact Analysis

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. The Refinery is not within 100 km of the nearest Class I area, which is the Wichita Mountains Wildlife Refuge (WMWR). The Refinery is approximately 143 km from the WMWR. Therefore, the Refinery was not evaluated for its impacts on the WMWR.

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Subpart KKK is Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they existed on September 1, 2005, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, Subpart BBBB, Subpart DDDD, Subpart HHHH, and Appendix G. NSPS requirements are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
<u>Part 5</u> includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual EU that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

1. 5 TPY of any one criteria pollutant
2. 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule

Emission and operating limitations have been established based on information in the permit application and Permits No. 98-172-C (M-15) (PSD) and 98-172-C (M-18) (PSD).

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-17 (Incinerators) [Not Applicable]
This subchapter specifies design and operating requirements and emission limitations for incinerators, municipal waste combustors, hospital, medical, and infectious waste incinerators, and commercial and industrial solid waste incineration units. Thermal oxidizers, flares, and any other air pollution control devices are exempt from Part 1 of this subchapter for incinerators. This facility does not have any municipal waste combustors, hospital, medical, and infectious waste incinerators, and commercial and industrial solid waste incineration units. The incinerators at the refinery are considered thermal oxidizers, flares, and other air pollution control devices.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. All of the small (<10 MMBTUH) fuel-burning units are fired with refinery fuel-gas or diesel fuel. Fuel-burning equipment with a rated heat input between 10 and 1,000 MMBTUH are limited to between 0.599 and 0.20 lb/MMBTU as defined in Appendix C. Fuel-burning unit is defined as "any internal combustion engine or gas turbine or any other combustion device used to convert the combustion of fuel into usable energy." Since thermal oxidizers, flares, and incinerators are pollution control devices designed to destroy pollutants and are not used to convert fuel into usable energy, they do not meet the definition of fuel-burning unit and are not subject to these requirements. The FCCU regenerators and the CCR also do not convert combustion of fuel into usable energy, except for the CO boilers, therefore, are not considered fuel-burning units. The following tables list all fuel-burning equipment affected by this permit and their associated emissions.

	Description	**Rating**	**SC 19 Limit**	**Emissions**
EU	**Boilers**	**MMBTUH**	**lb/MMBTU**	**lb/MMBTU**
B-253	CO Boiler	144.0	0.32	0.01
B-254	Boiler/CO Boiler	144.0	0.32	0.01
B-801	Boiler	72.5	0.38	0.01
B-802	Boiler	89.8	0.36	0.01
B-803	Boiler	86.8	0.36	0.01
	Heaters			
H-101	Process Heater	30.8	0.46	0.01
H-102A	Process Heater	160.0	0.31	0.01
H-102B	Process Heater	135.0	0.32	0.01
H-103	Process Heater	102.6	0.35	0.01
H-201	Process Heater	116.7	0.34	0.01

	Description	**Rating**	**SC 19 Limit**	**Emissions**
EU	**Boilers**	**MMBTUH**	**lb/MMBTU**	**lb/MMBTU**
H-301	Process Heater	21.6	0.50	0.01
H-401A	Process Heater	16.0	0.54	0.01
H-401B	Process Heater	14.8	0.55	0.01
H-402A	Process Heater	13.9	0.56	0.01
H-402B	Process Heater	15.8	0.54	0.01
H-403	Process Heater	98.7	0.35	0.01
H-404/5	Process Heater	99.3	0.35	0.01
H-406	Process Heater	28.0	0.47	0.01
H-407	Process Heater	25.0	0.48	0.01
H-411	Process Heater	28.0	0.47	0.01
H-601	Process Heater	58.5	0.40	0.01
H-603	Process Heater	125.5	0.33	0.01
H-901	Process Heater	60.0	0.39	0.01
H-1013	Process Heater	2.4	0.60	0.01
H-5602	Hot Oil Heater	20.0	0.51	0.01
H-6501	Process Heater	92.1	0.35	0.01
H-6502	Process Heater	54.3	0.40	0.01
H-6701	Co-Processor Heater	11.8	0.59	0.01
H-15001	Process Heater	326.8	0.26	0.01
H-100024	Asphalt Tank Heater	13.5	0.56	0.01
H-210001	Process Heater	12.2	0.57	0.01
	Diesel Fired Engines			
C-80018	Detroit Diesel/8V-92TA	3.6	0.60	0.10
EEQ-8801	DMT/DMT-825D2	5.1	0.60	0.10
EEQ-80001	Cummins/6BT5.9G-2	0.6	0.60	0.10
EWCP-1	Caterpillar 3412	4.7	0.60	0.10
EWCP-2	Caterpillar 3412	4.7	0.60	0.10
EWCP-3	Caterpillar 3412	4.7	0.60	0.10

AP-42 (7/98), Section 1.4, Table 1.4-2, lists the total PM emissions for natural gas to be 7.6 lb/MMft^3 or about 0.0076 lb/MMBTU. The permit requires the heaters and boilers to be fired with either refinery fuel-gas or commercial grade natural gas to ensure compliance with Subchapter 19. Since all of the emission limits for the heaters and reboilers under Subchapter 19 are greater than the expected emissions from these units, having the permit require these units to only be fueled with refinery fuel gas or commercial grade natural gas will ensure compliance with this subchapter. AP-42 (10/96), Section 3.4, Table 3.4-1, lists the total PM emissions for diesel-fired engines to be 0.1 lb/MMBTU. The permit requires the use of diesel fuel in the plant compressor engine, the emergency generator engines and the fire-water pump engines to ensure compliance with Subchapter 19.

This subchapter also limits emissions of PM from directly fired fuel-burning units and industrial processes based on their process weight rates. For process rates up to 60,000 lb/hr (30 TPH), the allowable emission rate (E) in pounds per hour is interpolated using the formula in Appendix G ($E = 4.10*P^{(0.67)}$) where (P) is the process weight rate in tons per hour. For process rates in excess of 60,000 lb/hr (30 TPH), extrapolation of the allowable emission limit is accomplished using this equation ($E = 55.0*P^{(0.11)}-40$). Emission limits established by Subchapter 19 include the front-half and back-half of the PM sampling train. Therefore, representative emissions from these emission units include the anticipated emissions from both the front-half and the back-half of the sampling train and are greater than the limits that will be established in the permit. Listed in the following table are the process weight rates for the EU affected by this permit, the estimated emissions, and the allowable emission limits.

EU	**Source**	**Rate (TPH)**	**SC 19 Limit (lb/hr)**	**Emissions (lb/hr)**
HI-801	Asphalt Blowstill & TO	10.64	19.99	0.69
FGS-200	FCCU Regenerators[1]	1,443	82.43	51.34
cat_hop	FCCU Catalyst Hopper Vent	700	73.06	3.77
HI-501	SRU Incinerator	5.45	15.40	0.43
CCR	Platformer CCR Vent	0.50	2.58	0.56
H-5601	SRU/TGTU w/Incinerator	21.2	31.73	0.40
HI-8801	WWTP Incinerator	0.01	0.23	0.12

[1] - Based only on the catalyst recirculation rate.

The Asphalt Blowstill and WWTP incinerators only combust waste gases and no specific requirements are needed for these emission units to ensure compliance with this subchapter. The FCCU Regenerators and Catalyst Hopper will be vented to a WS. The permittee will be required to monitor and record the WS operating parameters as shown in the BACT analysis. The SRU tail gas incinerators combust waste gases and refinery fuel-gas as auxiliary fuel and no specific requirements are needed for these emission units to ensure compliance with this subchapter. PM emissions from the Platformer CCR are controlled using a series of internal screens and cyclones. Since the catalyst is very expensive, every effort is made to recover it and minimize air emissions. The CCR is subject to NESHAP, Subpart UUU and is vented to a wet scrubber to control emissions of HCl. Therefore, monitoring under the NESHAP will ensure compliance with this subchapter.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case, shall the average of any six-minute period exceed 60% opacity. EU subject to an opacity limit under NSPS are exempt from the requirements of this subchapter. When burning refinery fuel-gas in the combustion units (process heaters and boilers) there is little possibility of exceeding the opacity standards. The FCCU is subject to an opacity limit under NSPS, Subpart J. The Asphalt Blowstill, Platformer CCR, #1 SRU/TGTU, #2 SRU/TGTU, WWTP Incinerator, and diesel fired engines are also subject to this subchapter. For the Asphalt Blowstill and diesel-fired engines (except for small

engines used only during emergencies), the permit will require a daily observation of each stack and opacity readings to be conducted if visible emissions are detected. Since the # 1 & #2 SRU/TGTU and WWTP Incinerator combust waste gases and refinery fuel gas, there is little possibility of exceeding the opacity standards for these units. The Platformer CCR is vented to a wet scrubber and also has very little possibility of exceeding the opacity standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of sulfur dioxide (SO_2) emissions from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). This part also limits the impact of H_2S emissions from any new or existing source. Recent modeling conducted using ISCST3 was used to show the impacts of the facility on the ambient air as shown in the following tables.

Ambient Impacts of SO_2 (Preliminary Analysis)

Averaging Time	Standard µg/m³	Impact µg/m³
5-minute*	1,300	1,072
1-hour*	1,200	652
3-hour	650	587
24-hour	130	119

* - Based on the PSD modeling preliminary analysis and adjustment factors for different averaging periods.

Ambient Impacts of H_2S (TV Application)

Averaging Time	Standard µg/m³	Impact µg/m³
24-hour	278	22

Emissions from all of the equipment have been modeled and have been shown to be in compliance with these standards.
Part 5 limits SO_2 emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. This is equivalent to approximately 1,203 ppmv sulfur in the fuel gas. All fuel-burning equipment constructed or modified after June 11, 1973, which combust refinery fuel gas are subject to NSPS, Subpart J, which limits the amount of H_2S in the fuel gas to 0.1 grains/DSCF or approximately 162 ppmv. The refinery fuel gas has a HHV of approximately 800 BTU/SCF, which is equivalent to approximately 0.0336 lb SO_2/MMBTU. The permit will require all new fuel-burning equipment to be fired with refinery

fuel gas with a limit of 0.1 grains/DSCF, except for the diesel fired engines and the FCCU CO boilers.
For liquid fuels the limit is 0.8 lb/MMBTU. All liquid fuels combusted at the facility are low-sulfur fuel oil with a maximum sulfur content of 0.05 percent. AP-42 (9/98), Chapter 1.3, Table 1.3-1, gives an emission factor of 142*S pound of SO_2 per 1,000 gallons which is approximately 0.05 lb/MMBTU when S = 0.05% by weight sulfur in the fuel oil. This emission rate is in compliance with the limitation of 0.8 lb/MMBTU. The permit will require the use of fuel oil with a maximum sulfur content of 0.05 % sulfur by weight for the diesel fired engines.
Part 5 also requires new fuel-burning equipment with a heat input greater than 250 MMBTUH to meet other continuous monitoring requirements. There is only one heater (H-15001) that is rated greater than 250 MMTBUH (327 MMBTUH). However, EUs combusting only gaseous fuel containing less than 0.1% by weight sulfur are exempt from these requirements. H-15001 is fired with refinery fuel gas with a maximum sulfur content of 0.1 grains/DSCF, which is approximately 0.00034% by weight sulfur.
Part 5 requires removal or oxidation of H_2S from the exhaust gas of any new petroleum or natural gas process equipment. Oxidation of the H_2S must be conducted in a system that assures at least a 95% reduction of the H_2S in the exhaust gases and that is equipped with an alarm system to signal non-combustion of the exhaust gases. This does not apply to EUs that emit less than 0.3 lb/hr of H_2S.

Emissions from the existing liquid sulfur storage pit, liquid sulfur storage tank, and the regenerated amine storage tanks are estimated below the exemption level. However, the liquid sulfur storage tank will be vented to the SRU incinerator. The railcar loading operations are calculated to have emissions of approximately 0.58 lb/hr/railcar based on the maximum loading rate and is subject to this requirement. For facilities with an SRU prior to release to the atmosphere, Subchapter 31 requires the SRU to meet a calculated sulfur reduction efficiency based on the SRU capacity. The existing SRU has a capacity of approximately 119 LTD and the new SRU will have a capacity of approximately 130 LTD. The required SO_2 reduction efficiency for units with a capacity greater than 5 LTD but less than 150 LTD is calculated using the following formula: $Z = 92.34 \times (X^{0.00774})$, where X is the sulfur feed rate in LTD. Based on this formula and the capacity of the existing and new SRU, the required sulfur reduction efficiencies are 95.8% and 95.9%, respectively. The SRU reduction efficiencies are expected to exceed 98% and 99.8%, respectively. All applicable requirements will be incorporated into the permit.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
NO_X emissions are limited to 0.20 lb/MMBTU heat input, three hour average, from all gas-fired fuel-burning equipment constructed after February 2, 1972, with a rated heat input of 50 MMBTUH or greater. The FCCU regenerators, CCR, and incinerators do not meet the definition of fuel-burning equipment and are not subject to this subchapter. All of the fuel-burning equipment rated greater than 50 MMBTUH are listed in the table on the following page. All emissions from the heaters and boilers are in compliance with this subchapter.

EU	**Description Heaters**	**Const./Mod. Date**	**Rating MMBTUH**	**SC 33 Limit lb/MMBTU**	**Emissions lb/MMBTU**
H-102A	Process Heater	1998	160.0	0.20	0.045
H-102B	Process Heater	1998	135.0	0.20	0.059
H-103	Process Heater	1974	102.6	0.20	0.098
H-201	Process Heater	1974	116.7	0.20	0.098
H-403	Process Heater	1975	98.7	0.20	0.098
H-404/5	Process Heater	1980	99.3	0.20	0.098
H-601	Process Heater	1974	58.5	0.20	0.098
H-603	Process Heater	1992	125.5	0.20	0.066
H-901	Process Heater	1969	60.0	0.20	0.098
H-6501	Process Heater	1992	92.1	0.20	0.060
H-6502	Process Heater	1992	54.3	0.20	0.060
H-15001	Process Heater	1992	326.8	0.20	0.060
	Boilers				
B-253	CO Boiler	2005	144.0	0.20	0.060
B-254	Boiler/CO Boiler	2005	144.0	0.20	0.060
B-801	Boiler	1974	72.5	0.20	0.098
B-802	Boiler	1975	89.8	0.20	0.098
B-803	Boiler	1975	86.8	0.20	0.098

OAC 252:100-35 (Carbon Monoxide) [Applicable]
Subchapter 35 requires new petroleum catalytic cracking and petroleum reforming units to reduce CO emissions by use of complete secondary combustion of the waste gas generated. Removal of 93 percent or more of the carbon monoxide generated is considered equivalent to secondary combustion. The FCCU Regenerators are subject to this subchapter. The FCCU No. 1 Regenerator reduces CO emissions by secondary combustion in the CO Boilers. The FCCU No. 2 Regenerator is a full combustion unit with CO emissions at or near the detection limit. The FCCU No. 2 Regenerator combust the remaining coke from the catalyst that was not combusted in the FCCU No. 1 Regenerator. The FCCU No. 2 Regenerator is also vented through the CO Boilers.

While this rule is not specific about compliance with the alternative standard for OAC 252:100-35, the intent of the regulation is to reduce emissions of CO to a level which is represented by complete combustion. Complete combustion of CO can be shown in other ways such as through operational parameters and exhaust gas CO concentrations. Based on average combustion processes, CO emissions from combustion units that are operating properly average 500 ppmv and range from 1,000 to 50 ppmv.

Operation of the FCCU No. 1 and 2 Regenerators within the established NSPS, Subpart J, CO limit of 500 ppmv in the exhaust gases should assure compliance with the intent of Subchapter 35 (complete combustion).

The Platformer CCR is considered a petroleum catalytic reforming unit and is also subject to this subchapter. Compliance with a CO limit of 0.44 lb/hr in the exhaust gases from the regenerator should assure compliance with the intent of Subchapter 35. The modified permit will also include a requirement to show compliance with the new emission limit quarterly.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
<u>Part 1</u> requires all vapor-loss control devices, packing glands, and mechanical seals required by this subchapter to be properly installed, maintained, and operated.
<u>Part 3</u> requires storage vessels constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Storage vessels subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. All of the storage vessels at this facility constructed after the effective date are either subject to NSPS or store a VOC with a vapor pressure less than 1.5 psia under actual storage conditions and are exempt from this rule.
<u>Part 3</u> requires storage vessels constructed after December 28, 1974, with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than or equal to 1.5 psia to be a pressure vessel or to be equipped with an external floating roof or a fixed roof with an internal floating cover, or to be equipped with a vapor recovery system capable of collecting 85% of the uncontrolled VOC. Storage vessels subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. The oil-water separators (V-8801 & V-8802) are not storage vessels. All of these storage vessels are either subject to NSPS or store a VOC with a vapor pressure less than 1.5 psia under actual storage conditions and are exempt from this rule.
<u>Part 3</u> applies to VOC loading facilities constructed after December 24, 1974. Facilities with a throughput greater than 40,000 gallons/day are required to be equipped with a vapor-collection and disposal system unless all loading is accomplished by bottom loading with the hatches of the tank truck or trailer closed. Loading facilities subject to the requirements of NSPS, Subpart XX or NESHAP, Subpart R are exempt from these requirements. The light products loading terminal at the refinery is equipped with a vapor-collection and disposal system and the VOC railcar loading terminal will be equipped with a vapor-collection and disposal system. These terminals are also subject to NESHAP, Subpart R and are exempt from these requirements.
<u>Part 5</u> limits the VOC content of coatings used in coating operations or lines. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
<u>Part 7</u> requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency. This facility flares all emissions that are not processed by a vapor recovery system.
<u>Part 7</u> requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion. All equipment at the refinery is operated to minimize emissions of VOC.

Part 7 requires any single or multiple-compartment VOC/water separator that receives effluent water containing more than 200 gallons per day of any VOC, from any equipment processing, refining, storing, or handling VOCs to comply with one of the following sets of conditions:

1. The container shall totally enclose the liquid contents and all openings shall be sealed;
2. The container shall be equipped with an external floating roof with a pontoon type or double deck type cover, or a fixed roof with an internal floating cover. The cover shall rest on the surface of the contents and be equipped with a closure seal, or seals, to close the space between the cover and container wall;
3. The container shall be equipped with a vapor recovery system that consists of a vapor-gathering system capable of collecting the VOC vapors and gases discharged and a vapor-disposal system capable of processing such vapors and gases to prevent their emission to the atmosphere; or
4. The container is approved prior to use and is equipped with controls that have efficiencies equal to the controls in listed in OAC 252:100-37(1-3).

For each of the systems, all gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place and the oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair are in progress. The two oil-water separators (V-8801 & V-8802) are equipped with external floating roofs and are subject to NSPS, Subpart QQQ which requires controls equal to or greater than the requirements of OAC 252:100-37(1-3). Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands that are properly installed and maintained in good working order and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. Equipment subject to NSPS, Subpart GGG are exempt from these requirements. The equipment affected by this permit at the refinery are subject to the requirements of NSPS, Subpart GGG and NESHAP, Subpart CC and are not subject to this rule.

OAC 252:100-41 (Hazardous Air Pollutants) [Not Applicable]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on September 1, 2005, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS and TTTTT are hereby adopted by reference as they exist on September 1, 2005. These standards apply to both existing and new sources of HAPs. These requirements are covered in the “Federal Regulations” section.

Part 5 was a **state-only** requirement governing sources of toxic air contaminants that have emissions exceeding a *de minimis* level. However, Part 5 of Subchapter 41 has been superseded by OAC 252:100-42, effective June 15, 2006.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superceded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this project:

OAC 252:100-7	Permit for Minor Facilities	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-23	Cotton Gins	not type of EU
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Existing Municipal Solid Waste Landfills	not in source category

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
This facility is a PSD major source. This project affects earlier PSD determinations. The PSD requirements for this modification are addressed in the "PSD Review" section. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60 [Subparts Db, Dc, J, Kb, GGG, and QQQ are Applicable]
Subparts D and Da, Fossil Fired Steam Generators. These subparts affect any fossil-fuel-fired steam generating unit with a heat input rate of 250 MMBTUH. Only one EU exceeds 250 MMBUTH and it is not considered a steam generator.

	Description	**Rating**	**Const.**
EU	**Heaters**	**MMBTUH**	**Date**
H-15001	Process Heater	326.8	1992

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity greater than 100 MMBTUH and that commenced construction, modification, or reconstruction after June 19, 1984. All of the units greater than 100 MMBTUH are shown in the table below.

	Description	**Rating**	**Const.**
EU	**Boilers**	**MMBTUH**	**Date**
B-253	CO Boiler	144.0	2004-5
B-254	Boiler/CO Boiler	144.0	2004-5
	Heaters		
H-102B	Process Heater	135.0	1998
H-102A	Process Heater	160.0	1998
H-103	Process Heater	102.6	1974
H-201	Process Heater	116.7	1974
H-603	Process Heater	125.5	1992
H-15001	Process Heater	326.8	1992

Most of the EUs meet the definition of process heaters and are not affected units. Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. Both of the listed CO boilers are subject to this subpart and all applicable requirements have been incorporated into the permit.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity between 10 and 100 MMBTUH and that commence construction, modification, or reconstruction after June 9, 1989. All of the units less than 100 MMBTUH are shown in the table below.

	Description	**Rating**	**Const./Mod.**
EU	**Boilers**	**MMBTUH**	**Date**
B-801	Boiler	72.5	1968
B-802	Boiler	89.8	1975
B-803	Boiler	86.8	1979
	Heaters		
H-101	Process Heater	30.8	1998
H-301	Process Heater	21.6	1974
H-401A	Process Heater	16.0	1969
H-401B	Process Heater	14.8	1974
H-402A	Process Heater	13.9	1970
H-402B	Process Heater	15.8	1970
H-403	Process Heater	98.7	1980
H-404/5	Process Heater	99.3	1980
H-406	Process Heater	28.0	1974
H-407	Process Heater	25.0	1974
H-411	Process Heater	28.0	1986
H-601	Process Heater	58.5	1975
H-901	Process Heater	60.0	1969
H-1013	Process Heaters (2)	2.4 Ea.	1954
H-5602	Hot Oil Heater	20.0	2004
H-6501	Process Heater	92.1	1992
H-6502	Process Heater	54.3	1992
H-6701	Co-Processor Heater	11.8	2004
H-100024	Asphalt Tank Heater	13.5	1999
H-210001	Aspahlt Tank Heater	12.2	1996

Most of the EUs meet the definition of process heaters and/or were constructed prior to the applicability date and are not affected units. Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. The Hot Oil Heater (H-5602) and Asphalt Tank Heaters (H-100024 and H-210001) are considered steam generating units since they heat oil, which is then used to transfer heat to other materials, and are subject to this subpart. All applicable requirements have been incorporated into the permit. These EUs are subject to the fuel recordkeeping requirement of this subpart since they do not combust coal, wood, oil and/or a mixture of these fuels. Per 40 CFR 60.48(g) the owner/operator of each affected EU will be required to record and maintain records of the amounts of each fuel combusted during each month since the potential SO_2 emissions rate of refinery fuel gas is typically below 0.32 lb/MMBTU (~1,540 ppmv H_2S & ~0.95 gr H_2S/DSCF @ 800 BTU/SCF).

Subpart I, Hot Mix Asphalt Facilities. This facility does not manufacture hot mix asphalt by heating and drying aggregate and mixing with asphalt cements. This facility only manufactures asphalt cements.

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: fuel gas combustion devices, FCCU catalyst regenerators, and Claus sulfur recovery plants.

Fuel Gas Combustion Devices

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. All fuel gas combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H_2S limitation of 0.10 grains of H_2S/DSCF which is required to be continuously monitored and recorded. All of the heaters and boilers are considered refinery fuel gas combustion devices. The heaters and boilers subject to this subpart based on the date of construction or modification are listed in the following table.

	Description	**Rating**	**Const./Mod.**
EU	**Boilers**	**MMBTUH**	**Date**
B-802	Boiler	89.8	1977
B-803	Boiler	86.8	1979
B-253	CO Boiler	144.0	2004
B-254	Boiler/CO Boiler	144.0	2004
	Heaters		
H-101	Process Heater	30.8	1998
H-102B	Process Heater	135.0	1998
H-102A	Process Heater	160.0	1998
H-103	Process Heater	102.6	1974
H-201	Process Heater	116.7	1974
H-301	Process Heater	21.6	1974
H-401B	Process Heater	14.8	1974
H-403	Process Heater	98.7	1980
H-404/5	Process Heater	99.3	1980
H-406	Process Heater	28.0	1985
H-407	Process Heater	25.0	1974
H-411	Process Heater	28.0	1985
H-601	Process Heater	58.5	1974
H-603	Process Heater	125.5	1992
H-5602	Hot Oil Heater	20.0	2004
H-6501	Process Heater	92.1	1992

EU	Description Boilers	Rating MMBTUH	Const. Date
H-6502	Process Heater	54.3	1992
H-6701	Co-Processor Heater	11.8	2004
H-15001	Process Heater	326.8	1992
H-100024	Asphalt Tank Heater	13.5	1999
H-210001	Aspahlt Tank Heater	12.2	1996

The CO boilers are affected units but only due to the supplemental refinery fuel gas they combust. Fuel gas combusted by the affected units must be monitored and recorded and can be done at one location. Based on 1998 monitoring data, the typical sulfur content of the refinery fuel gas used at the Valero Refinery is 0.027 grains of H_2S/DSCF. The boiler and process heaters in the following table are not subject to this subpart since they were constructed prior to the applicability date.

EU	Description Boilers	Rating MMBTUH	Const./Mod. Date
B-801	Boiler	72.5	1974
H-401A	Process Heater	16.0	1969
H-402A	Process Heater	13.9	1970
H-402B	Process Heater	15.8	1963
H-901	Process Heater	60.0	1969
H-1013	Process Heaters (2)	2.4 Ea.	1954

The flares and thermal oxidizers listed in the following table are also considered fuel gas combustion devices and are also subject to the fuel gas sulfur content limitation.

EU	Description	Rating MMBTUH	Const./Mod. Date
Crude Unit Flare	Process Flare	27.0	1976
HI-81001	West flare	28.0	1993
LPLT	Gasoline Loading Rack Vapor Combustor	N/A	1996
HI-8801	WWTP Incinerator	15.0	2004

The Alternate Flares were constructed prior to the applicability date of this subpart and are not subject to this subpart. Since the Asphalt Blowstill and Thermal Oxidizer are subject to NESHAP, Subpart LLLL, it is not subject to this subpart per **§** 63.8681(e).

EU	Description	Rating MMBTUH	Const./Mod. Date
altfl	Alternate Crude Unit Flare	27.0	<1968
altfl	Alternate Alkylation Unit Flare	28.0	<1968
HI-801	Asphalt Blowstill and Thermal Oxidizer	N/A	1992

Alternative monitoring plans (AMPs) for the following units were submitted and approved by EPA:

1. CCR Catalyst Disengagement Purge Gas System (HI-81001, H-404 and H-405);
2. CCR Catalyst Regeneration Purge Gas System (H-404 and H-405);
3. Tank Truck Loading Dock Vapors (LPLT);
4. Isomerization Unit Desiccant Dryers Purge Vapors (HI-81001); and
5. Pressure Swing Absorption (PSA) Off-Gas System (H-15001);

<u>CCR Catalyst Disengagement & Regeneration Purge Gas Systems</u>
Daily Monitoring of the H_2S content of the H_2 feed to the reformer unit using Draeger tubes and the reformer feedstock and reformer product sulfur concentration using ASTM 2622 with semi-annual submission of the data was accepted by the EPA. If the feedstock or product sulfur content exceeds 81 ppm, the purge gas streams to HI-81001, H-404, and H-405 must be monitored daily and approval of the AMP is considered withdrawn.

<u>Tank Truck Loading Dock Vapors</u>
The submittal satisfied the one time monitoring requirement for this type of fuel gas combustion device and no additional monitoring was required.

<u>Isomerization Unit Desiccant Dryers Purge Vapors</u>
Daily Monitoring of the H_2S content of the Isomerization Unit Dessicant Dryer using Draeger tubes with semi-annual submission of the data was accepted by the EPA.

<u>PSA Off-Gas System</u>
Daily Monitoring of the H_2S content from the outlet of the zinc oxide bed of the PSA Off-Gas System using Draeger tubes with semi-annual submission of the data was accepted by the EPA.

If the gas stream compositions of the submitted AMPs change the approval of the AMPs are considered withdrawn and must be resubmitted for approval.

<u>FCCU Catalyst Regenerators</u>
All FCCU catalyst regenerators that commence construction or modification after June 11, 1973, are subject to the following limitations:

1) A PM emission limitation of 1.0 lb/1,000 lbs of coke burn-off, which is required to be continuously monitored and recorded (when exhaust gases discharged from the FCCU are combusted by a waste heat boiler in which supplemental liquid or solid fuel is burned PM in excess of this limit may be emitted which shall not exceed 0.1 lb/MMBTU of heat input);
2) A 30% opacity limitation, except for one six-minute average opacity reading in any one hour period;
3) A CO emission limitation of 500 ppmdv, which is required to be continuously monitored and recorded; and

4) One of the following SO_2 emission limitations:
   a) For units with an add-on control device, a requirement to reduce SO_2 emissions by 90% or to maintain SO_2 emissions to less than 50 ppmv, whichever is less stringent; or
   b) For units without an add-on control device, an SO_2 emission limitation of 9.8 lbs/1,000 lbs of coke burn-off; or
   c) A limit of the 0.30 percent by weight or less sulfur in the FCCU fresh feed.

   Compliance with these limits must be determined based on continuous monitoring and a seven day rolling average.

FCCU catalyst regenerators that commenced construction or modification prior to January 17, 1984, are exempt from the SO_2 emission limit. The FCCU was modified after 1984 and is subject to this entire subpart. All applicable requirements for the FCCU Regnerators have been incorporated into the permit. The Platformer CCR is considered a catalytic reforming unit and is not subject to this subpart.

Claus Sulfur Recovery Plants
For Claus sulfur recovery plants with an oxidation control system or a reduction control system followed by incineration, Subpart J limits SO_2 emissions to 250 ppmvd at 0% excess air. The existing and new SRUs are subject to this emission limit, continuous emission monitoring, and the recordkeeping and reporting requirements of this subpart. All applicable requirements have been incorporated into the permit.

Subpart K, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons but less than 65,000 gallons and which commenced construction, reconstruction, or modification after March 8, 1974, or which have a capacity greater than 65,000 gallons and which commenced construction, reconstruction, or modification after June 11, 1973, but prior to May 19, 1978. The table below lists all tanks constructed, reconstructed, or modified between these dates and applicable capacities.

EUG	Tank	Roof Type	Contents	Barrels	VP Psia	Const. Date
1	T-1008	Cone	LCO Slurry	2,115	0.150	1975
14	T-1082	External Floating	Crude Oil	124,714	RVP 5	1974
15	T-1083	External Floating	Crude Oil	124,714	RVP 5	1974
19	T-1102	Cone	Asphalt	75,786	0.014	1975
28	T-1125	External Floating	Gasoline	124,398	RVP 10.5	1974
29	T-1126	External Floating	Gasoline	124,412	RVP 10.5	1974
30	T-1127	Cone	Diesel/Kerosene	80,579	0.008	1974
31	T-1128	Cone	Diesel/Kerosene	80,639	0.008	1974
32	T-1129	Cone	Diesel/Kerosene	2,113	0.008	1975

Petroleum liquids does not include Nos. 2 through 6 fuel oils, gas turbine fuel oils Nos. 2–GT through 4–GT, or diesel fuel oils Nos. 2–D and 4–D. The diesel/kerosene storage vessels store these types of fuel oils and are not subject to this subpart. Also, any storage vessels storing petroleum liquids with a true vapor pressure less than 1.5 psia do not have to meet the control requirements of this subpart. This would include the asphalt, LCO Slurry, and CFHT Filter Flush storage vessels. Therefore, only storage vessels T-1082, T-1083, T-1125, and T-1126 would be subject to the control requirements of this subpart. However, NESHAP, Subpart CC overlap requirements states that any storage vessel subject to NSPS, Subpart K and NESHAP, Subpart CC is only required to comply with NESHAP, Subpart CC. All of the storage vessels listed above are only required to comply with NESHAP, Subpart CC. The following table shows all storage vessels constructed prior to NSPS, Subpart K. All of these storage vessels are subject to NESHAP, Subpart CC.

					VP	**Const.**
EUG	**Tank**	**Roof Type**	**Contents**	**Barrels**	**Psia**	**Date**
2	T-1018	External Floating	NHT Charge	62,850	2.800	1953
3	T-1019	External Floating	Alkylate	66,868	RVP 15	1948
6	T-1118	Cone	Asphalt	79,742	0.014	1970
8	T-1135	Cone	PMA Asphalt	362	1.322	1968
17	T-1085	Cone	Slurry/Fuel Oil #6	55,319	0.0002	1953
19	T-1151	Cone	Asphalt	206,979	0.014	1953
20	T-1111	Cone	Asphalt	55,011	0.014	1954
21	T-1113	Cone	Asphalt	131,005	0.014	1959
22	T-1115	External Floating	Gasoline	27,205	RVP 10.5	1953
23	T-1116	External Floating	Gasoline	27,315	RVP 10.5	1953
24	T-1121	Cone	Diesel/Kerosene	40,526	0.008	1968
26	T-1123	Cone	Gasoline	60,766	RVP 10.5	1968
27	T-1124	External Floating	Gasoline	111,721	RVP 10.5	1972
39	V-815	Cone	Wastewater FO	1,731	0.001	1968
40	V-818	Cone	Slop Oil	444	0.010	1968

Subpart Ka, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids that have a storage capacity greater than 40,000 gallons and which commenced construction, reconstruction, or modification after May 18, 1978, and prior to July 23, 1984.

					VP	**Const.**
EUG	**Tank**	**Roof Type**	**Contents**	**Barrels**	**Psia**	**Date**
16	T-1084	External Floating	Crude Oil	124,714	RVP 5	1978
33	T-1130	External Floating	FCCU Gasoline	79,414	RVP 15	1978
34	T-1131	External Floating	Gasoline	125,100	11.00	1979
35	T-1132	External Floating	Reformate	80,138	11.00	1979

Any storage vessels storing petroleum liquids with a true vapor pressure less than 1.5 psia do not have to meet the control requirements of this subpart. This would include the asphalt storage vessel T-1113. All of the other storage vessels are subject to the control requirements of this subpart. However, NESHAP, Subpart CC overlap requirements states that any Group 1 storage vessel subject to NSPS, Subpart Ka and NESHAP, Subpart CC is only required to comply with NESHAP, Subpart CC. All of the storage vessels not subject to this subpart are also subject to NESHAP, Subpart CC.

Subpart Kb, VOL Storage Vessels. This subpart affects storage vessels for VOL that have a storage capacity greater than 19,813 gallons and which commenced construction, reconstruction, or modification after July 23, 1984. The following storage vessels are only required to keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel:

- Storage Vessels with a capacity greater than or equal to 39,890 gallons that store a liquid with a maximum true vapor pressure less than 0.5076 psia; or
- Storage Vessels with a capacity greater than or equal to 19,813 but less than 39,890 gallons that store a liquid with a maximum true vapor pressure less than 2.1756 psia.

In addition to records of capacity, the following storage vessels are also only required to maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period:

- Storage Vessels with a capacity greater than or equal to 39,890 gallons that store a liquid with a maximum true vapor pressure less than 0.7542 psia; or
- Storage Vessels with a capacity greater than or equal to 19,813 but less than 39,890 gallons that store a liquid with a maximum true vapor pressure less than 4.0031 psia.

The table below lists all storage vessels constructed after July 23, 1984, with a capacity greater than 19,813 gallons.

EUG	Tank	Roof Type	Contents	Barrels	VP Psia	Const. Date
4	T-153	Cone	FCCU Charge	200,676	0.002	2003
36	T-1141	Cone	Diesel/Kerosene	119,189	0.080	1992
37	T-1142	Cone	Diesel/Kerosene	79,445	0.080	1992
43	T-813	Cone	Amine	1,007	0.010	1992
46	T-210003	Cone	Asphalt Flux	3,021	0.041	1996
46	T-210004	Cone	PMA Rxn	6,526	0.041	1996
46	T-210005	Cone	PMA Rxn	6,526	0.041	1996
46	T-210006	Cone	PMA	10,197	0.041	1996
46	T-210007	Cone	PMA	10,197	0.041	1996
46	T-210008	Cone	PMA	11,715	0.041	2001
47	T-100149	Cone	Asphalt Flux	35,847	0.135	1996

					VP	Const.
EUG	**Tank**	**Roof Type**	**Contents**	**Barrels**	**Psia**	**Date**
47	T-100150	Cone	Asphalt Base	35,847	0.135	1996
48	T-1152	External Floating	Sour Water	11,890	0.349	1999
49	T-83001	Cone	Sour Water	18,905	0.010	1993
168	T-1155	External Floating	Naptha	163,555	1.322	2003
169	T-156	Cone	FCCU Slurry	56,000	0.028	2003

The definition of storage vessel under this subpart does not include process tanks which are defined as tanks that are used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations. The Oil-Water Separators are considered process tanks because they are used to separate the water and oil in the wastewater stream (a unit operation) and the recovered oil (a raw material) is then transferred to another tank for storage before being sent back through the refining process.

Most of the storage vessels do not store a VOL with a vapor pressure greater than 0.5 psia and are only subject to the requirement to keep for the life of the storage vessel a record of it’s capacity. The naphtha storage vessel (T-1155) and Sour Water Storage Vessel (T-1152) are subject to the control requirements of this subpart. Since the overlap requirements of NESHAP, Subpart CC state that if a storage vessel at an existing source is subject to NSPS, Subpart Kb it is only required to comply with NSPS, Subpart Kb, these storage vessels are still subject to this subpart and all applicable requirements will be incorporated into the permit.

Subpart GG, Stationary Gas Turbines. There are no turbines located at this facility.

Subpart UU, Asphalt Processing and Asphalt Roofing Manufacture. This subpart affects each asphalt storage vessel and each blowing still at petroleum refineries. Asphalt Storage Vessels and blowing stills that process and/or store asphalt used for roofing and other purposes and that commenced construction or modification after November 18, 1980, are subject to the requirements of this subpart. Asphalt Storage Vessels and blowing stills that process and/or store only non-roofing asphalt and that commenced construction or modification after May 26, 1981, are also subject to the requirements of this subpart. The Asphalt Blowstill was altered in 1992. However, since only the blowstill thermal oxidizer was replaced and no increase in emissions resulted from the project, the modification was not considered a modification under NSPS. Therefore, the Asphalt Blowstill is not subject to the requirements of this subpart.

EU	**Point**	**Description**
HI-801	P-117	Asphalt Blowstill and Thermal Oxidizer

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI). NSPS, Subpart GGG requires equipment in VOC service to comply with paragraphs §§ 60.482-1 through 60.482-10, 60.484, 60.485, 60.486, and 60.487 except as provided in § 60.593. All equipment in VOC service affected under this permit is subject to NSPS, Subpart GGG or NESHAP Subpart CC.

Subpart XX, Bulk Gasoline Terminals. This subpart affects loading racks at bulk gasoline terminals which deliver liquid product into gasoline tank trucks and that commenced construction or modification after December 17, 1980. The light products loading terminal at the refinery was built prior to the applicable effective date of this subpart and was later modified to comply with NESHAP, Subpart CC. The new VOC railcar loading rack will be subject to NESHAP, Subpart CC. Due to the overlap requirements of NESHAP, Subpart CC and since these are Group 1 loading racks, the loading racks are only subject to NESHAP, Subpart CC.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after January 4, 1983, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGG requires the leak detection, repair, and documentation procedures of NSPS, Subpart VV. All affected equipment in VOC service and not in HAP service is subject to this subpart. After the effective date of 40 CFR Part 63 NESHAP, Subpart CC, (August 18, 1998), all equipment in organic HAP service is subject only to Subpart CC, which also requires compliance with NSPS, Subpart VV. All applicable requirements have been incorporated into this permit.

Subpart III, VOC Emissions from SOCMI Air Oxidation Unit Processes. This subpart affects facilities with air oxidation reactors that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.617. The Asphalt Blowstill is the only air oxidation process at the facility and it does not produce a listed chemical.

Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart sets standards for natural gas processing plants which are defined as any site engaged in the extraction of natural gas liquids from field gas, fractionation of natural gas liquids, or both. This facility does not extract natural gas liquids from field gas or fractionate natural gas liquids.

Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions. This subpart affects each sweetening unit and each sweetening unit followed by a SRU that process natural gas which commenced construction or modification after January 20, 1984. Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. This facility only processes gases that are generated at the facility from the processing of crude oil.

Subpart NNN, VOC Emissions from SOCMI Distillation Operations. This subpart affects facilities that are a part of a process unit that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.667. This facility produces listed chemicals and uses distillation to separate the desired product. However, none of the distillation and recovery process streams are vented to the atmosphere.

Subpart OOO, Nonmetallic Mineral Processing Plants. This subpart affects each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station at nonmetallic mineral processing plants. This facility does not crush or grind any nonmetallic minerals.

Subpart RRR, VOC Emissions from SOCMI Reactor Processes. This subpart affects facilities that are a part of a process unit that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.707. This facility produces listed chemicals and has a reactor to produce the desired products. However, all streams from the reactors are recovered. There are no vent streams to control.

Subpart QQQ, VOC Emission from Petroleum Refinery Wastewater Systems. This subpart applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. Oil-water wastewater separators shall be equipped with a fixed roof or a floating roof, which meets the required specifications. Group 1 wastewater streams that are managed under this subpart that are also subject to the provisions of NESHAP, Subpart CC are only required to comply with Subpart CC which requires compliance with NESHAP, Subpart FF. Subpart FF allows oil-water separators to comply with the requirements for alternative standards for oil-water separators of Subpart QQQ. This facility is subject to the requirements of NESHAP, Subpart CC. However, the Oil-Water Separators comply with the Alternative Standards for Oil-Water Separators of this subpart.

NESHAP, 40 CFR Part 61 [Subpart FF is Applicable]

Subpart J, Equipment Leaks (Fugitive Emission Sources) of Benzene. This subpart affects process streams that contain more than 10% benzene by weight. The maximum benzene concentration in any product stream at this site is 5% in super unleaded gasoline, and only trace amounts are expected in the refinery fuel gas.

Subpart FF, Benzene Waste Operations. This subpart affects benzene-contaminated wastewater at petroleum refineries. Facilities with 10 metric tons of benzene are required to manage and treat the waste streams. This facility has elected to manage and treat the facility wastes such that the benzene quantity in the wastes is equal to or less than 6.0 metric tons per year.

NESHAP, Part 63, Subpart CC, requires all Group 1 wastewater streams to comply with §§ 61.340 through 61.355 of 40 CFR Part 61, Subpart FF, for each process wastewater stream that meets the definition in § 63.641. All applicable requirements have been incorporated into this permit.

NESHAP, 40 CFR Part 63 [Subparts CC, UUU, and LLLLL are Applicable]
Subpart G, Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater. Subpart CC requires all Group 1 storage vessels to comply with §§ 63.119 through 63.121 of Subpart G. The Group 1 storage vessels are listed in the NESHAP, Subpart CC section. Storage Vessels subject to NSPS, Subpart Kb are not subject due to the overlap provisions of NESHAP, Subpart CC.

Subpart Q, Industrial Cooling Towers. This subpart applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources as defined in § 63.401. This facility does not have or use industrial process cooling towers that are operated with chromium-based water treatment chemicals.

Subpart R, Gasoline Distribution Facilities. Bulk gasoline terminals or pipeline breakout stations with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with Subpart CC, §§ 63.646, 63.648, 63.649, and 63.650 are not subject to this subpart, except as specified in Subpart CC, § 63.650. Subpart CC, § 63.650(a) requires all facilities to comply with Subpart R, §§ 63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3). Subpart CC § 63.650(b) states that all terms not defined in § 63.641 shall have the meaning given them in Subpart A or in 40 CFR part 63, Subpart R and that the definition of "affected source" in § 63.641 applies under this section. § 63.650(c) requires all gasoline loading racks regulated under Subpart CC to comply with the compliance dates specified in § 63.640(h). All applicable requirements of this subpart, as per Subpart CC, are incorporated into the permit for the light products loading terminal and the VOC railcar loading station.

Subpart CC, Petroleum Refineries. This subpart, promulgated on August 18, 1995, affects the following process units and related emission points at petroleum refineries: miscellaneous process vents from petroleum refining process units, storage vessels associated with petroleum refining process units, wastewater streams and treatment operations associated with petroleum refining process units, and equipment leaks from petroleum refining process units; gasoline loading racks, marine vessel loading operations, and all storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station. The affected emission points are listed with a summary of applicable requirements.
Petroleum refining process units are defined as a process unit engaged in petroleum refining as defined in the SIC code for petroleum refining (SIC 2911) and used primarily for the following:

1. Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;
2. Separating petroleum; or
3. Separating, cracking, reacting, or reforming intermediate petroleum streams.

Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants. Catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, sulfur recovery plant vents and fuel gas emission points were specifically exempted from this subpart.

Miscellaneous Process Vents From Petroleum Refining Process Units

Miscellaneous process vent means a gas stream containing greater than 20 ppmv organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit meeting the criteria specified in § 63.640(a). Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. Miscellaneous process vents include vent streams from: caustic wash accumulators, distillation tower condensers/accumulators, flash/ knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum (steam) ejectors, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. Miscellaneous process vents do not include:

1. Gaseous streams routed to a fuel gas system;
2. Relief valve discharges;
3. Leaks from equipment regulated under § 63.648;
4. Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations;
5. In situ sampling systems (onstream analyzers);
6. Catalytic cracking unit catalyst regeneration vents;
7. Catalytic reformer regeneration vents;
8. Sulfur plant vents;
9. Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;
10. Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;
11. Coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge, deheading, draining, or decoking (coke cutting) or pressure testing after decoking;

12. Vents from storage vessels;
13. Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and
14. Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

The Valero Ardmore Refinery has 59 process vents which might be defined as Group 1 miscellaneous process vents. Of these vents, 25 are routed to the fuel gas recovery, treatment, and distribution system(s) and are not defined as miscellaneous process vents. The remaining 34 process vents serve various processing functions and are either routed back to the process or to one of the two flares. All applicable requirements have been incorporated into the permit for these vents.

Storage Vessels Associated with Petroleum Refining Process Units, Bulk Gasoline Terminals, or Pipeline Breakout Stations

Group 1 storage vessels at existing source are storage vessels with a design capacity greater than or equal to 46,758.5 gallons (1,113.3 barrels) that store a liquid with a maximum true vapor pressure greater than or equal to 1.5084 psia and an annual average true vapor pressure greater than or equal to 1.2038 psia and has an annual average HAP concentration greater than 4 % by weight. Group 2 storage vessels means a storage vessel that does not meet the definition of a Group1 storage vessel.

Group 1 Storage Vessels Subject to NESHAP, Subpart CC

					VP	
EUG	**Tank**	**Roof Type**	**Contents**	**Barrels**	**Psia**	**% HAP**
2	T-1018	External Floating	NHT Charge	62,580	2.800	16.3
3	T-1019	External Floating	Alkylate	66,868	RVP 15	6.0
14	T-1082	External Floating	Crude Oil	124,714	RVP 5	13.7
15	T-1083	External Floating	Crude Oil	124,714	RVP 5	13.7
16	T-1084	External Floating	Crude Oil	124,714	RVP 5	13.7
22	T-1115	External Floating	Gasoline	27,205	RVP 10.5	17.0
23	T-1116	External Floating	Gasoline	27,315	RVP 10.5	17.0
26	T-1123	Cone	Gasoline	60,766	RVP 10.5	17.0
27	T-1124	External Floating	Gasoline	111,721	RVP 10.5	17.0
28	T-1125	External Floating	Gasoline	124,398	RVP 10.5	17.0
29	T-1126	External Floating	Gasoline	124,412	RVP 10.5	17.0
33	T-1130	External Floating	FCCU Gasoline	79,414	RVP 15	17.0
34	T-1131	External Floating	Gasoline	125,100	11.00	17.0
35	T-1132	External Floating	Reformate	80,138	11.00	21.6

Group 2 Storage Vessels Subject to NESHAP, Subpart CC

EUG	Tank	Roof Type	Contents	Barrels	VP Psia	% HAP
1	T-1008	Cone	LCO Slurry	2,089	0.150	4.6
6	T-1118	Cone	Asphalt	79,742	0.014	3.4
8	T-1135	Cone	PMA Asphalt	362	1.322	1.3
17	T-1085	Cone	Slurry/Fuel Oil #6	55,319	0.0002	4.6
19	T-1102	Cone	Asphalt	75,786	0.014	3.4
19	T-1151	Cone	Asphalt	206,979	0.014	3.4
20	T-1111	Cone	Asphalt	55,011	0.014	3.4
21	T-1113	Cone	Asphalt	131,055	0.014	3.4
24	T-1121	Cone	Diesel/Kerosene	40,526	0.008	0.8
30	T-1127	Cone	Diesel/Kerosene	80,579	0.008	0.8
31	T-1128	Cone	Diesel/Kerosene	80,639	0.008	0.8
32	T-1129	Cone	Slop Oil	2,113	0.010	0.8
38	V-523	Cone	Amine	895	0.136	<0.1
39	V-815	Cone	WW Fallout	1,731	0.130	<0.1
40	V-818	Cone	Slop Oil	444	0.010	0.2
N/A	T-5801	Cone	Lean Amine	1,119	0.136	<0.1
42	T-811	Cone	Spent Caustic	1,007	N/A	<0.1
42	T-812	Cone	Spent Caustic	1,007	N/A	<0.1
42	T-814	Cone	Spent Caustic	1,007	N/A	<0.1
172	TK-5801	Cone	Amine	895	0.136	<0.1
173	TK-5602	Cone	Sulfur	3,644	N/A	<1.0

Group 1 and Group 2 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subpart Kb are only required to comply with the provisions of NSPS, Subpart Kb except as provided in § 63.640(n)(8)(i) through (vi). These storage vessels are listed in the NSPS, Subpart Kb section. Group 1 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subparts K or Ka are only required to comply with this subpart. Group 2 storage vessels that are part of an existing source and that are subject to the control requirements of NSPS, Subparts K or Ka are only required to comply with NSPS, Subparts K or Ka. Group 2 storage vessels that are part of an existing source and that are not subject to the control requirements of NSPS, Subparts K or Ka are only required to comply with this subpart. Group 1 Storage Vessels not subject to NSPS, Subpart Kb are required to comply with the requirements of §§ 63.119 through 63.121 except as provided in § 63.646(b) through § 63.646(l). The owner or operator of these storage vessels are required to reduce HAP emissions to the atmosphere either by operating and maintaining a fixed roof and internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, or a closed vent system and control device, or routing the emissions to a process or a fuel gas system. The facility is also required to meet certain work practices and conduct inspections and maintain the tank seals similar to the requirements of NSPS, Subpart Kb. All applicable requirements have been incorporated into the permit.

<u>Wastewater Streams and Treatment Operations Associated w/Petroleum Refining Process Units</u>
The wastewater streams and treatment operations associated with petroleum refining process units in organic HAP service are subject to this subpart and are required to comply with the requirements of this subpart. This subpart requires equipment that is used to manage a Group 1 wastewater stream to comply with the requirements of this subpart and 40 CFR §§ 61.340 through 61.355, NESHAP, Subpart FF. For Group 1 wastewater streams managed in a piece of equipment that is also subject to the provisions of NSPS, Subpart QQQ the equipment is only required to comply with the requirements of this subpart. All applicable requirements have been incorporated into the permit.

<u>Equipment Leaks from Petroleum Refining Process Units, Bulk Gasoline Terminals, or Pipeline Breakout Stations</u>
All equipment in organic HAP service is required to comply with the provisions of 40 CFR Part 60, Subpart VV and 63.648(b), except as provided in § 63.648(a)(1), (a)(2), and (c) through (i). All equipment subject to NSPS, Subpart GGG and this subpart is only required to comply with this subpart. All applicable requirements have been incorporated into the permit.

<u>Gasoline Loading Racks or Pipeline Breakout Stations</u>
Gasoline loading racks are required to comply with Subpart R, §§ 63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3). The Light Products Loading Rack and VOC railcar loading rack are subject to this section and all applicable requirements have been incorporated into the permit. This facility does not have a pipeline breakout stations.

<u>Marine Vessel Loading Operations</u>
There are no marine vessel loading operations at this facility.

<u>Subpart UUU</u>, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and SRU. This subpart, affects the following EUs:

1. The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (*i.e.*, the catalyst regeneration flue gas vent);
2. The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation;
3. The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery; and

4. Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

An affected source is a new affected source if the facility commenced construction of the affected source after September 11, 1998. An affected source is an existing affected source if it is not new or reconstructed. All existing affected sources are required to comply with this subpart by April 11, 2005, except as provided by § 63.1563(c). All new sources are required to comply with this subpart as follows:

1. If startup of the new affected source was prior to April 11, 2002, then it must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002.
2. If startup of the new affected source was after April 11, 2002, then it must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of the affected source.

FCCU Catalyst Regeneration Flue Gas Vents

Inorganic HAP Standard

Catalytic cracking units subject to the NSPS, Subpart J, PM emissions limit ($\leq$ 1 lb/1,000 of coke burn off) must comply with the NSPS Subpart J, PM emission limit. The FCCU regenerators are subject to the NSPS, Subpart J emission limit and comply with that limit. Since the facility uses a wet scrubber to control emissions the facility has applied for an AMP to include monitoring of the liquid-to-gas ratio rather than a continuous opacity monitor to show compliance with this standard. The facility is required to monitor the coke burn off rate daily and the hours of operation of the FCCU Regenerators. Since the CO boilers do not combust solid or liquid fossil fuels, fuel combustion monitoring is not required for the CO boilers.

Organic HAP Standard

Catalytic cracking units subject to the NSPS, Subpart J, CO emissions limits ($\leq$ 500 ppmdv @ 0% O_2) must comply with the NSPS Subpart J, CO emission limit. The FCCU regenerators are subject to the NSPS, Subpart J emission limit and comply with that limit. The FCCU uses a CEM to show compliance with this standard on an hourly basis.

Catalytic Reforming Unit Process Vents

The Platformer CCR is a catalytic reforming unit and will be subject to this subpart, since the CCR was recently modified.

Inorganic HAP Standard

Catalytic reforming units must comply with one of the inorganic HAP emission limits of § 63.1567(a)(1)(i) (Vent to a Flare that meets the control device requirements of § 63.11) or (ii) (reduce uncontrolled TOC emissions by 98 % or to less than 20 ppmvd @ 3% O_2) during initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. These emission limits do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents. They also do not apply to emissions from process vents during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less. The facility complies with both options depending upon the operating periods within the CCR operation cycle. The facility is required to continuously monitor the flare's pilot light for the presence of a flame and the daily average combustion zone temperature of the heaters used to control emissions. When vent streams are introduced into the flame zone of the process heaters, no monitoring is required. The CCR purge and depressurization gases are vented to the flame zones of H-403 and H-404/H-405. The pilot light of the west flare is monitored continuously.

Organic HAP Standard

Continuous catalytic reforming units must comply with the organic HAP emission limits of § 63.1566(a)(1)(ii) (Reduce uncontrolled emissions of HCl by 97% by weight or to a concentration of 10 ppmvd @ 3% O_2) during coke-burn off and catalyst rejuvenation. The facility installed a wet scrubber and vents the emissions from the coke burn off and rejuvenation to the wet scrubber. The facility is required to monitor the daily average pH of the scrubbing liquid and liquid to gas ratio and maintain them at or above levels established during the initial performance tests (≥ 8.0 and 1.85, respectively).

Sulfur Recovery Units

Sulfur recovery units subject to the NSPS, Subpart J, SO_2 emission limit (≤ 250 ppmvd @ 0% O_2) must comply with the NSPS Subpart J, SO_2 emission limit. The new and existing SRUs are subject to NSPS, Subpart J and will meet all applicable requirements of this subpart and NSPS, Subpart J. The SRUs use a CEM to show compliance with this standard on a 12-hour rolling average basis.

Bypass Lines

Bypass lines must meet the work practice standards in Table 36 of this subpart. There are no bypass lines for the FCCU or CCR. The SRUs have bypass lines that are vented to the east flare system. The facility uses flow monitoring devices to determine if flow is present in the lines hourly.

An operation, maintenance, and monitoring plans was required to be prepared and submitted for the FCCU, CCR, SRUs, and Bypass Lines. The facility submitted the plan with their initial compliance demonstration and their startup, shutdown, and malfunction plan. All applicable requirements of this subpart have been incorporated into the permit.

Subpart EEEE, Organic Liquids Distribution (Non-Gasoline). This subpart affects organic liquid distribution (OLD) operations at major sources of HAPs with an organic liquid throughput greater than 7.29 million gallons per year (173,571 barrels/yr). This subpart affects the following EUs at existing facilities:

1. Storage Vessels with a capacity ≥ 20,000 gallons but < 40,000 gallons that store an organic liquid that contains > 5% HAPs and that has an annual average vapor pressure ≥ 1.9 but < 11.1 psia;
2. Storage Vessels with a capacity ≥ 40,000 gallons that store an organic liquid that contains > 5% HAPs and that has an annual average vapor pressure ≥ 0.75 psia.
3. Transfer racks that loads at any position ≥ 11.8 million liters (3.12 million gallons) per year of organic liquids into a combination of tank trucks and railcars.

Sources controlled under another NESHAP are exempt from this subpart. There are no OLD operations subject to this subpart.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affect RICE with a site rating greater than 500 brake horsepower and which are located at a major source of HAPs. This facility is a major source of HAPs. New or reconstructed emergency or limited use stationary RICE does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(d). Emergency stationary RICE is any stationary RICE that operates in an emergency situation. Limited use stationary RICE is any stationary RICE that operates less than 100 hours per year. The stationary RICE connected to the emergency generators (EUs: EEQ-8801 & EEQ-80001) and emergency water curtain (EUs: EWCP-1 through EWCP-3) are considered emergency stationary RICE and are not subject to this subpart. The stationary RICE attached to the Instrument/Plant Air Compressor (C-80018) is rated less than 500-hp and is not subject to this subpart.

Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters. This subpart affects boilers and/or process heaters located at a major source of HAPs. Existing boilers and process heaters that are in the large gaseous fuels subcategory are only subject to the initial notification requirements. They are not subject to the emission limits, work practice standards, performance testing, monitoring, startup shutdown and maintenance plan, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in Subpart A. Existing and new boilers and process heaters in the small gaseous fuels subcategory are not subject to this subpart or the initial notification requirements. Small gaseous fuel units are units with a heat rating of less than or equal to 10 MMBTUH. Temporary boilers as defined in this subpart are not subject to this subpart. Most of the heaters at this facility are in the existing large gaseous fuel subcategory and are not subject to this subpart.

New boilers and process heaters are boilers and process heaters that commenced construction after January 13, 2003, and are subject to this subpart. This subpart establishes emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at a major source of HAP. Large gaseous fuel units are units with a heat rating greater than 10 MMBTUH.

This facility is a major source of HAP. The new boilers and process heaters in the large gaseous fuels subcategory are required to meet a CO emission limit of 400 ppmvd @ 3 % O_2 (30-day rolling average for units with a heat input of 100 MMBTUH or greater; 3-run average for units with a heat input of less than 100 MMBBTUH). New large gaseous fuel boilers and process heaters with a heat input less than 100 MMBTUH must conduct an initial performance test and annual performance tests thereafter to show compliance with the CO emission limit. New large gaseous fuel boilers and process heaters with a heat input rating greater than 100 MMBTUH must install continuous emission monitors. None of the new boilers or process heaters are rated greater than 100 MMBTUH. The facility must also develop a written start-up, shutdown, and malfunction plan and site-specific monitoring plan for each of the affected units. The boiler subject to this subpart are shown below and are required to demonstrate compliance with this subpart within 180 days of operation including initial compliance testing.

EU	Description	MMBTUH	Const. Date
H-5602	Hot Oil Heater	20.0	2004
H-6701	Co-Process Heater	11.8	2004

Subpart GGGGG, Site Remediation. This subpart is applicable to facilities that conduct a site remediation which cleans up a remediation material at a facility that is co-located with one or more other stationary sources that emit HAP and meet the affected source definition. This facility is a major source of HAP and currently conducts site remediation at the facility.

Site remediation at a facility is not subject to this subpart, except for the recordkeeping requirements specified in § 63.7881(c), if the site remediation meets the all of the following conditions:

1. Before beginning the site remediation, you determine that for the remediation material to be excavated, extracted, pumped, or otherwise removed during the site remediation that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) is less than 1.10 TPY.
2. The facility prepares and maintains at the facility written documentation to support the determination of the total HAP quantity used to demonstrate compliance with § 63.7881(c)(1). The documentation must include a description of the methodology and data used for determining the total HAPs content of the material.
3. This exemption may be applied to more than one site remediation at the facility provided that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) for all of the site remediations exempted under this provision are less than 1.10 TPY.

This facility has documented that all of the site remediations at the facility total less than 1.10 TPY and is only subject to the recordkeeping requirements of this subpart.

Subpart LLLLL, Asphalt Processing. This subpart affects asphalt processing facilities and asphalt roofing manufacturing lines at major sources of HAPs. The asphalt processing facility at the refinery is subject to this subpart. Asphalt processing facilities include: asphalt flux blowing stills, asphalt flux storage tanks storing asphalt flux intended for processing in the blowing stills, oxidized asphalt storage tanks, and oxidized asphalt-loading racks. The provisions of subpart J of 40 CFR part 60 do not apply to emissions from asphalt processing facilities subject to this subpart. This subpart does not apply to any equipment that is subject to subpart CC of this part or to subpart K, Ka, or Kb of 40 CFR part 60. Each blowing still, Group 1 asphalt loading rack, and Group 1 asphalt storage tank at existing, new, and reconstructed asphalt processing facilities; are required to meet one of the following requirements:

1. Reduce total hydrocarbon (THC) mass emissions by 95 percent, or to a concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen;
2. Route the emissions to a combustion device achieving a combustion efficiency of 99.5 percent;
3. Route the emissions to a combustion device that does not use auxiliary fuel achieving a THC destruction efficiency of 95.8 percent;
4. Route the emissions to a boiler or process heater with a design heat input capacity of 44 megawatts (MW) or greater;
5. Introduce the emissions into the flame zone of a boiler or process heater; or
6. Route emissions to a flare meeting the requirements of § 63.11(b).

The Asphalt Blowstill and Thermal Oxidizer (EU HI-801) are subject to the requirements of this subpart. The Asphalt Blowstill is vented to the Thermal Oxidizer and must maintain the three hour average combustion zone temperature at or above the operating limit established during the initial performance test. The refinery has elected to reduce the THC emissions to a concentration of 20 ppmvd @ 3% O_2. The initial performance testing established a relationship between the minimum combustion zone temperature and the asphalt blowstill production rate. The facility has requested an alternative monitoring location for the stack temperature. The facility monitors the temperature in a location upstream of the flame zone rather than in the flame zone to help prevent frequent replacement of the thermocouple. The facility has developed and implemented a site-specific monitoring plan according to the provisions of § 63.8688 (g) and (h).

Asphalt loading rack means the equipment at an asphalt processing facility used to transfer oxidized asphalt from a storage tank into a tank truck, rail car, or barge. Group 1 asphalt loading rack means an asphalt loading rack loading asphalt with a maximum temperature of 500 °F or greater and with a maximum true vapor pressure (MTVP) of 1.5 psia or greater. The Asphalt and No. 6 Fuel Oil Railcar and Truck Loading Racks (EUs AsRail & As Truk) are considered Group 2 loading racks since they do not load asphalt with a temperature of 500 °F or greater and with a MTVP of 1.5 psia or greater. The facility monitors the temperature of the asphalt processed to the loading racks daily.

Asphalt storage tank means any tank used to store asphalt flux, oxidized asphalt, and modified asphalt, at asphalt roofing manufacturing facilities, petroleum refineries, and asphalt processing facilities. Group 1 asphalt storage tank means an asphalt storage tank that has a capacity of 47,000 gallons of asphalt or greater and stores asphalt at a maximum temperature of 500 °F or greater and has a MTVP of 1.5 psia or greater. The asphalt storage tanks located at the facility store asphalt at temperatures below 500 °F and with MTVP less than 1.5 psia. Group 2 asphalt storage tank means any asphalt storage tank with a capacity of 2.128 Tons (~497 gallons) of asphalt or greater that is not a Group 1 asphalt storage tank. Group 2 asphalt storage vessels are required to limit exhaust gases to 0% opacity. This subpart does not apply to any equipment that is subject to NESHAP, Subpart CC or to NSPS, Subparts K, Ka, or Kb. The table below lists all Group 2 storage vessels and the subpart that they are subject to.

EUG	Tank	Roof Type	Contents	Barrels	Subpart
6	T-1118	Cone	Asphalt	79.742	NESHAP, CC
19	T-1102	Cone	Asphalt	75,786	NESHAP, CC
19	T-1151	Cone	Asphalt	206,979	NESHAP, CC
20	T-1111	Cone	Asphalt / Fuel Oil	55,011	NESHAP, CC
21	T-1113	Cone	Asphalt	131,005	NESHAP, CC
46	T-210003	Cone	Asphalt	3,021	NSPS, Kb
46	T-210004	Cone	Asphalt	6,526	NSPS, Kb
46	T-210005	Cone	Asphalt	6,526	NSPS, Kb
46	T-210006	Cone	Polymer Asphalt	10,197	NSPS, Kb
46	T-210007	Cone	Polymer Asphalt	10,197	NSPS, Kb
46	T-210008	Cone	Polymer Asphalt	11,715	NSPS, Kb
47	T-100149	Cone	Asphalt	35,000	NSPS, Kb
47	T-100150	Cone	Asphalt	35,000	NSPS, Kb

The affected facilities must comply with the emission limitations (including operating limits) at all times, except during periods of startup, shutdown, and malfunction, and develop and implement a written startup, shutdown, and malfunction plan (SSMP) and site-specific monitoring plan. All applicable requirements have been incorporated into the permit.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM) applies to any pollutant specific EU at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

1. It is subject to an emission limit or standard for an applicable regulated air pollutant;
2. It uses a control device to achieve compliance with the applicable emission limit or standard; and
3. It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source levels.

The requirements of this part shall not apply to any of the following emission limitations or standards:

1. Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act; and
2. Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in § 64.1.

Continuous compliance determination method (CCDM) means a method, specified by the applicable standard or an applicable permit condition, which:

1. Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and

2. Provides data either in units of the standard or correlated directly with the compliance limit.

The following emission units use a control device or are a control device that is used to meet an applicable emission limit or standard:

EU	**Description**	**Pollutant**	**CCDM**
CU Flare	Crude Unit Process Flare	VOC	CPM[1]
HI-801	Asphalt Blowstill Thermal Oxidizer	VOC[4]	CPM[2]
		CO	CPM[2]
HI-81001	West Flare	VOC	CPM[1]
LPLT	LPLT Thermal Oxidizer	VOC[4]	CPM[2]
FGS-200	FCCU Regenerators Flue Gas Scrubber	NO_X	CEM
		CO	CEM
		SO_2	CEM
		PM_{10}	CPM[3]
HI-501	#1 SRU Incinerator	H_2S/SO_2	CEM
Cat_Hop	FCCU Catalyst Hopper Vent Wet Scrubber	PM_{10}	CPM[3]
CCR	CCR - H-403, H-404/405	VOC[4]	CPM[2]
H-5601	#2 SRU Incinerator	H_2S/SO_2	CEM
HI-8801	WWTP Incinerator	VOC[4]	CPM[2]
SSP-520	Sulfur Storage Pit	H_2S[5]	Flared[1]
MSLA-520	Molten Sulfur Railcar Loading Arm	H_2S[5]	Flared[1]
RCALOAD 900	VOC Railcar Loading Station	VOC[4, 5]	Flared[1]
LPG	LPG Loading Station	VOC[5]	Flared[1]

CPM - Continuous Parameter Monitoring: [1] - Presence of Flare's Pilot light; [2] - Continuous Temperature Monitoring; and [3] - Wet Scrubber Liquid-to-Gas Ratio.

[4] - NESHAP.

[5] - Less than major source thresholds prior to control.

The EUs with CEMs are exempt from the requirements of this part. Some of the EUs are subject to a NESHAP and are also exempt from this part. The flares use continuous monitoring of the pilot light to ensure compliance with the applicable emission limitations or standards. The FCCU monitors the liquid to gas ratio continuously to ensure compliance with the applicable emission limitations and standards. The permit requires the permittee to continuously monitor the FCCU WS operational parameters established during initial testing (WGS liquid to gas ratio, liquid flow rate, and pressure drop) to ensure compliance with the PM_{10} emission limits.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
This facility handles naturally occurring hydrocarbon mixtures at a refinery and the Chemical Accident Prevention Provisions are applicable to this facility. The facility was required to submit the appropriate emergency response plan prior to June 21, 1999. The facility has submitted their plan which was given EPA No. 12005 for EPA Facility No. 1000 00128177. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
<u>Subpart A</u> identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
<u>Subpart F</u> requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The Standard Conditions of the permit address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION VIII. TIER CLASSIFICATION, PUBLIC REVIEW, AND FEES

A. Tier Classification and Public Review

This permit has been determined to be a Tier II based on the request for a significant modification of a Tier II construction permit. The applicant has published the "Notice of Filing a Tier II Application" in the *Daily Ardmoreite*, a daily newspaper, in Carter County on August 31, 2006. The notice stated that the application was available for review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, and at the AQD main office. The applicant published the "Notice of Tier II Draft Permit" in the *Daily Ardmoreite*, a daily newspaper, in Carter County on January 7, 2007. The notice stated that the draft permit was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, the AQD main office, and on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. No comments were received from the public. This facility is located within 50 miles of the Oklahoma - Texas border. The state of Texas has been notified of the draft permit. This permit was approved for concurrent EPA and public review. Since there were no comments from the public, the draft permit is deemed the proposed permit. No comments were received from the EPA on the draft/proposed permit.

B. Fees Paid

Construction permit application fee for an existing Part 70 source of $1,500.

SECTION IX. SUMMARY

The applicant has demonstrated the ability to comply with all applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. Compliance and Enforcement concur with the issuance of this permit. Issuance of the amended/modified construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Valero Refining Company - Oklahoma **Permit No. 98-172-C (M-19) (PSD)**
Valero Ardmore Refinery

The permittee is authorized to construct and modify operations in conformity with the specifications submitted to Air Quality on December 30, 1998, April 21, 2000, June 10, 2002, January 23, 2003, March 24, 2003, October 6, 2003, September 9, 2003, January 15, 2004, January 20, 2004, June 24, 2004, July 19, 2004, August 3, 2006, and all other supplemental materials. The Evaluation Memorandum dated February 6, 2007, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. As required by applicable state and federal regulations, the permittee is authorized to construct, and/or operate, the affected equipment in conformity with the specifications contained herein. Commencing construction, or operations, under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Upon issuance of an operating permit, the permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions: [OAC 252:100-8-6(a)(1)]

a. The Crude Unit shall not process fresh feedstock at a rate to exceed 100 thousand barrels per day (MBPD) based on a 12-month rolling average.
b. The Fluid Catalytic Cracking Unit (FCCU) shall not process fresh feedstock at a rate to exceed 30,000 bbl/day based on a 12-month rolling average.
c. The Asphalt Blowstill shall not process fresh feedstock at a rate to exceed 16,000 bbl/day based on a 12-month rolling average.
d. The Polymer Modified Asphalt (PMA) Unit shall not produce PMA at a rate to exceed 4,200,000 barrels per year (BPY) based on a 12-month rolling total.
e. The permittee shall determine and record the throughputs of the Crude Unit, FCCU, Asphalt Blowstill, and PMA Unit (daily).
f. To determine compliance with the limits stated above the permittee shall average the daily throughputs recorded during a calendar month and then determine the 12-month rolling average using the monthly average of daily throughputs.
g. The #1 Sulfur Recovery Unit (SRU) shall not produce sulfur at a rate greater than 119 long tons per day (LTPD) based on a 365-day rolling average.
h. The #2 SRU shall not produce sulfur at a rate greater than 130 LTPD without oxygen (O_2) enrichment and 200 LTPD with O_2 enrichment based on a 365-day rolling average.

2. Emission limitations and standards for affected Emission Units (EU):

EUG 1 Storage Vessel T-1008. Potential emissions from EU T-1008 were based on a throughput of 2,275,243 BPY and actual emissions are considered insignificant (<5 tons per year (TPY)). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1008	P-1	Cone	LCO/Slurry	2,115

a. The permittee shall comply with National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. The storage vessel shall not store a VOC with vapor pressure (VP) greater than or equal to 1.5 psia under actual storage conditions. [OAC 252:100-37]
c. The permittee shall determine, using the methods specified in § 63.641, and maintain a record of the maximum true vapor pressure (MTVP) of the material stored in the storage vessel. [OAC 252:100-8-6(a)(3)]

EUG 2 Storage Vessel T-1018. There are no emission limits for EU T-1018 since this storage vessel is grandfathered but it is limited to the existing equipment as it is. Potential emissions from EU T-1018 were based on a throughput of 9,490,000 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1018	P-2	External Floating	Alkylate & Gasoline	62,850

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

EUG 3 Storage Vessel T-1019. There are no emission limits for EU T-1019 since this storage vessel is grandfathered but it is limited to the existing equipment as it is. Potential emissions from EU T-1019 were based on a throughput of 2,555,000 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1019	P-3	External Floating	Alkylate & Gasoline	66,868

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

EUG 4 Storage Vessel T-153. Potential emissions from EU T-153 were based on a throughput of 10,950,222 bbl/yr and a maximum liquid bulk temperature of 160 ºF. Actual emissions from this storage vessel are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-153	P-4	Fixed Roof	FCCU Charge /Asphalt	200,676

a. The permittee shall comply with New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

b. The throughput for EU T-153 shall not exceed 10,950,222 bbl/yr based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]

c. Records of throughput shall be maintained (monthly and 12-month rolling total). [OAC 252:100-8-6(a)(3)]

d. The temperature of the liquid shall not exceed 160 ºF. [OAC 252:100-8-6(a)(1)]

e. The temperature of the liquid shall be measured and recorded at least once daily. [OAC 252:100-8-6(a)(3)]

EUG 6 Storage Vessel T-1118. There are no emission limits established for EU T-1118 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1118 were based on a throughput of 733,674 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1118	P-6	Cone	Asphalt	79,742

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 8 Storage Vessel T-1135. There are no emission limits established for EU T-1135 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1135 were based on a throughput of 4,424 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1135	P-8	Cone	PMA Crosslinking Co-Polymer	362

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 14, 15, & 16 Storage Vessels T-1082, T-1083, and T-1084, respectively. The emission limit for EU T-1082, T-1083, and T-1084 was based on a total throughput of 100 thousand barrels per day (MBPD). These storage vessels are considered Group 1 Storage Vessels under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1082	P-14	External Floating	Crude Oil	124,714
T-1083	P-15	External Floating	Crude Oil	124,714
T-1084	P-16	External Floating	Crude Oil	124,714

VOC
TPY
11.3

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements
b. The permittee shall record the throughput of each of the storage vessels (monthly) and determine, using the methods specified in § 63.641, and record the MTVP of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 17 Storage Vessel T-1085. There are no emission limits established for EU T-1085 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1085 were based on a throughput of 447,964 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	**Point**	**Roof Type**	**Contents**	**Barrels**
T-1085	P-17	Cone	Slurry / #6 Fuel Oil	55,319

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 19 Storage Vessels T-1102 and T-1151. Potential emissions from EU T-1102 are based on a throughput of 1,100,000 BPY and actual emissions are considered insignificant (<5 TPY). There are no emission limits established for EU T-1151 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1151 were based on a throughput of 1,893,114 BPY and actual emissions are considered insignificant (<5 TPY). These storage vessels are considered Group 2 Storage Vessels under 40 CFR Part 63, Subpart CC.

EU	**Point**	**Roof Type**	**Contents**	**Barrels**
T-1102	P-19	Cone	Asphalt/Gas-Oil	75,786
T-1151	P-189	Cone	Asphalt	206,979

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessels including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. Storage Vessel T-1102 shall not store a VOC with VP greater than or equal to 1.5 psia under actual storage conditions. [OAC 252:100-37]
c. The permittee shall determine, using the methods specified in § 63.641, and maintain a record of the MTVP of the material stored in Storage Vessel T-1102. [OAC 252:100-8-6(a)(3)]

EUG 20 Storage Vessel T-1111. There are no emission limits established for EU T-1111 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1111 were based on a throughput of 506,757 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1111	P-20	Cone	Asphalt /Fuel Oil /Gas Oil	55,011

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 21 Storage Vessel T-1113. Potential emissions from EU T-1113 are based on a throughput of 1,200,548 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1113	P-22	Cone	Asphalt /Gas Oil	131,005

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. The storage vessel shall not store a VOC with VP greater than or equal to 1.5 psia under actual storage conditions. [OAC 252:100-37]
c. The permittee shall determine, using the methods specified in § 63.641, and maintain a record of the MTVP of the material stored in the storage vessel. [OAC 252:100-8-6(a)(3)]

EUG 22 Storage Vessel T-1115. There are no emission limits established for EU T-1115 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1115 were based on a throughput of 11,205,500 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1115	P-23	External Floating	Gasoline	27,205

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

EUG 23 Storage Vessel T-1116. There are no emission limits established for EU T-1116 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1116 were based on a throughput of 9,510,400 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1116	P-24	External Floating	Gasoline	27,315

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

EUG 24 Storage Vessel T-1121. There are no emission limits established for EU T-1121 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1121 are based on a throughput of 1,190,974 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1121	P-27	Cone	Diesel /Jet Fuel /Distillate	40,526

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 26 Storage Vessel T-1123. There are no emission limits established for EU T-1123 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1123 were based on a throughput of 2,735,640 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1123	P-29	External Floating	Gasoline /Diesel	60,766

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

EUG 27 Storage Vessel T-1124. There are no emission limits established for EU T-1124 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Potential emissions from EU T-1124 were based on a throughput of 2,735,640 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1124	P-30	External Floating	Gasoline	111,721

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

EUG 28 Storage Vessel T-1125. The emission limit for EU T-1125 was based on a throughput of 7,500,000 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1125	P-31	External Floating	Gasoline	124,398

VOC
TPY
12.0

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements
b. The permittee shall record the throughput of each of the storage vessels (monthly) and determine, using the methods specified in § 63.641, and record the MTVP of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 29 Storage Vessel T-1126. The emission limit for EU T-1126 was based on a throughput of 7,500,000 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1126	P-32	External Floating	Gasoline	124,412

VOC
TPY
12.0

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements
b. The permittee shall record the throughput of each of the storage vessels (monthly) and determine, using the methods specified in § 63.641, and record the MTVP of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 30 Storage Vessel T-1127. Potential emissions from EU T-1127 are based on a throughput of 3,300,000 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1127	P-33	Cone	Diesel / Jet Fuel	80,579

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. The storage vessel shall not store a VOC with VP greater than or equal to 1.5 psia under actual storage conditions. [OAC 252:100-37]
c. The permittee shall determine, using the methods specified in § 63.641, and maintain a record of the MTVP of the material stored in the storage vessel. [OAC 252:100-8-6(a)(3)]

EUG 31 Storage Vessel T-1128. Emissions from EU T-1128 are based on a throughput of 3,300,000 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1128	P-34	Cone	Diesel / Jet Fuel	80,639

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. The storage vessel shall not store a VOC with VP greater than or equal to 1.5 psia under actual storage conditions. [OAC 252:100-37]
c. The permittee shall determine, using the methods specified in § 63.641, and maintain a record of the MTVP of the material stored in the storage vessel. [OAC 252:100-8-6(a)(3)]

EUG 32 Storage Vessel T-1129. Emissions from EU T-1129 are based on a throughput of 61,264 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1129	P-35	Cone	Diesel / Jet Fuel	2,113

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. The storage vessel shall not store a VOC with VP greater than or equal to 1.5 psia under actual storage conditions. [OAC 252:100-37]
c. The permittee shall determine, using the methods specified in § 63.641, and maintain a record of the MTVP of the material stored in the storage vessel. [OAC 252:100-8-6(a)(3)]

EUG 33 Storage Vessel T-1130. The emissions limit for EU T-1130 was based on a throughput of 10,402,500 bbl/yr. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1130	P-36	External Floating	Gasoline	79,414

VOC
TPY
26.8

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

b. The permittee shall record the throughput of each of the storage vessels (monthly) and determine, using the methods specified in § 63.641, and record the MTVP of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 34 Storage Vessel T-1131. The emission limit for EU T-1131 was based on a throughput of 12,514,286 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1131	P-37	External Floating	Gasoline /FCCU Gasoline + ISOM + Hydrocracker Naptha	125,100

VOC
TPY
9.2

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements

b. The permittee shall record the throughput of each of the storage vessels (monthly) and determine, using the methods specified in § 63.641, and record the MTVP of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 35 Storage Vessel T-1132. The emission limit for EU T-1132 was based on a throughput of 12,514,286 BPY. This storage vessel is considered a Group 1 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1132	P-38	External Floating	Reformate	80,138

VOC
TPY
7.8

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.654 Reporting and Recordkeeping Requirements
b. The permittee shall record the throughput of each of the storage vessels (monthly) and determine, using the methods specified in § 63.641, and record the MTVP of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 36 Storage Vessel T-1141. Emissions from EU T-1141 are based on a throughput of 3,578,477 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1141	P-39	Cone	Diesel / Kerosene	119,189

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

EUG 37 Storage Vessel T-1142. Emissions from EU T-1142 are based on a throughput of 2,391,914 BPY and actual emissions are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1142	P-40	Cone	Diesel / Kerosene	79,445

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

EUG 38 Regenerated/Make Up Amine Storage Vessel (V-523). There are no emission limits established for EU V-523 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Emissions from this storage vessel are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
V-523	P-41	Cone	Amine	91

EUG 39 Storage Vessel V-815. There are no emission limits established for EU V-815 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Emissions from this storage vessel are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
V-815	P-42	Cone	Wastewater Fallout	1,731

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 40 Storage Vessel V-818. There are no emission limits established for EU V-818 since this storage vessel is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is. Emissions from this storage vessel are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
V-818	P-43	Cone	Slop Oil	444

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 41 Oil-Water Separators V-8801 & V-8802. The emission limit for EU V-8801 &V-8802 is based on a throughput of 9,560,914 BPY for each separator.

EU	Point	Roof Type	Contents	Barrels
V-8801	P-44	External Floating	Oil / Water	17,200
V-8802	P-45	External Floating	Oil / Water	17,200

VOC
TPY
14.7

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC, Wastewater Provisions of § 63.647 for the Oil-Water Separators (V-8801 and V-8802). [40 CFR 63.640-654]

   i. The permittee shall comply with the requirements of § 61.340 through § 61.355 of 40 CFR Part 61, Subpart FF. [§ 63.647(a)]

      A. The Oil-Water Separators (V-8801 and V-8802) shall comply with the Alternative Standards for Oil-Water Separators of 40 CFR § 61.352 and § 60.693-2(a).

b. The cover shall rest on the surface of the contents and be equipped with a closure seal, or seals, to close the space between the cover edge and container wall. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair is in progress. [OAC 252:100-37-37(2)]

c. The storage vessels shall not store a VOC with a maximum true vapor pressure greater than 11.0 psia under actual storage conditions. [OAC 252:100-37]

d. The permittee shall record the throughput of the storage vessels (monthly) and determine and record the true vapor pressure of the material stored in the storage vessels (quarterly) using the methods specified in § 63.641. [OAC 252:100-8-6(a)(3)]

e. Compliance with the emission limitation shall be based on the storage vessel throughputs and the most recent version of WATER9 program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 42 Storage Vessels T-811, T-812, & T-814. Actual emissions from these storage vessels are considered insignificant (<5 TPY). These storage vessels are considered Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	**Point**	**Roof Type**	**Contents**	**Barrels**
T-811	P-46	Cone	Spent Caustic	1,007
T-812	P-47	Cone	Spent Caustic	1,007
T-814	P-49	Cone	Spent Caustic	1,007

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessels including but not limited to:

   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 43 Storage Vessel T-813. Actual emissions from this storage vessel are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-813	P-48	Cone	Amine	1,007

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

EUG 44 Process Vessel T-210001. Actual emissions from this process vessel are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-210001	P-50	Cone	Polymer Asphalt	19

EUG 45 Storage Vessel T-210002. Emissions from this storage vessel are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-210002	P-51	Cone	10 % H_3PO_4	9,517

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessel including but not limited to:
   i. § 63.654 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).

EUG 46 Storage Vessels T-210003 through T-210008. Emissions from EU T-210003 through T-210008 are based on the following throughputs: 1,398,970; 2,100,000; 2,100,000; 1,400,000; 1,400,000; and 1,400,000; respectively; and a maximum liquid bulk temperature of *160 ºF*. Emissions from each of these storage vessels are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-210003	P-52	Cone	Asphalt	3,021
T-210004	P-52	Cone	Asphalt	6,526
T-210005	P-52	Cone	Asphalt	6,526
T-210006	P-52	Cone	Polymer Asphalt	10,197
T-210007	P-52	Cone	Polymer Asphalt	10,197
T-210008	P-52	Cone	Polymer Asphalt	11,715

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

EUG 47 Storage Vessels T-100149 and T-100150. Emissions from EU T-100149 and T-100150 are based on the following throughputs: 1,400,000; and 2,800,000; respectively; and a maximum liquid bulk temperature of 160 ºF. Emissions from each of these storage vessels are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-100149	P-53	Cone	Asphalt	35,847
T-100150	P-54	Cone	Asphalt	35,847

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

EUG 48 Sour Water Stripper Storage Vessel (T-1152). Emissions from EU T-1152 are based on a throughput of 2,131,286 BPY and operation of the storage vessel with an external floating roof and are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-1152	P-55	External Floating	Sour Water	11,890

a. The permittee shall comply with the applicable sections of NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel except as provided in NESHAP, 40 CFR Part 63, § 63.640(n)(8)(i) through (vi):
   i. §60.112b (a)(2) Standards for VOC;
   ii. §60.113b (b) Testing and Procedures;
   iii. §60.115b (b) Recordkeeping and Reporting Requirements; and
   iv. §60.116b Monitoring of Operations.
b. The storage vessel shall not store a VOC with vapor pressure (VP) greater than or equal to 11.11 psia under actual storage conditions.

EUG 49 Sour Water Stripper Storage Vessel (T-83001). Emissions from EU T-83001 are based on a throughput of 2,565,575 BPY and operation of the storage vessel with a barrier of diesel fluid and are considered insignificant (<5 TPY). This storage vessel is considered a Group 2 Storage Vessel under 40 CFR Part 63, Subpart CC.

EU	Point	Roof Type	Contents	Barrels
T-83001	P-184	Cone	Sour Water	18,885

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

b. EU T-83001 shall be operated with a barrier of diesel fluid. [OAC 252:100-8-6(a)(1)]

EUG 100 Process Heater (H-101). Emission limits and standards for EU H-101 are listed below. Emissions from H-101 are based on a maximum rated capacity (HHV) of 30.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas hydrogen sulfide (H_2S) concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-101	P-101	Process Heater	30.8

NO_X		CO	
lb/hr	TPY	lb/hr	TPY
3.0	13.2	2.5	11.1

a. EU H-101 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-101 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 101 Process Heater (H-102B). Emission limits and standards for EU H-102B are listed below. Emissions from H-102B are based on a maximum rated capacity (HHV) of 135 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X, which are based on an emission factor of 0.059 lb/MMBTU.

EU	Point	Description	MMBTUH
H-102B	P-102	Process Heater	135.0

NO_X		CO		PM_{10}		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
8.0	34.9	11.1	48.7	1.6	7.2	4.5	19.9

a. EU H-102B is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)
b. H-102B shall be operated with Low-NO_X burners (LNB). [OAC 252:100-8-34]
c. Emissions of NO_X from EU H-102B shall not exceed 0.059 lb/MMBTU. [OAC 252:100-8-34]
d. Fuel use (SCF) and heat content (BTU/SCF) for EU H-102B shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
e. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 102 Process Heater (H-102A). Emission limits and standards for EU H-102A are listed below. Emissions from H-102A are based on a maximum rated capacity (HHV) of 160 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X, which are based on an emission factor of 0.045 lb/MMBTU.

EU	Point	Description	MMBTUH
H-102A	P-103	Process Heater	160.0

NO_X		CO		PM_{10}		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
7.2	31.5	13.2	57.7	1.8	8.5	5.4	23.5

a. EU H-102A is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. H-102A shall be operated with LNB. [OAC 252:100-8-34]

c. Emissions of NO_X from EU H-102A shall not exceed 0.045 lb/MMBTU. [OAC 252:100-8-34]

d. Fuel use (SCF) and heat content (BTU/SCF) for EU H-102A shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

e. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 103 Process Heater (H-403). Emission limits and standards for EU H-403 are listed below. Emissions from H-403 are based on a maximum rated capacity (HHV) of 98.7 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	**Point**	**Description**	**MMBTUH**
H-403	P-104	Process Heater	98.7

NO_X		**CO**		**SO_2**	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
9.7	42.4	8.1	35.6	3.3	14.5

a. EU H-403 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-403 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 104 Process Heater (H-404/5). Emission limits and standards for EU H-404/5 are listed below. Emissions from H-404/5 are based on a maximum rated capacity (HHV) of 99.3 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	**Point**	**Description**	**MMBTUH**
H-404/5	P-105/6	Process Heater	99.3

NO_X		**CO**		**SO_2**	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
9.7	42.6	8.2	35.8	3.3	14.6

a. EU H-404/5 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-404/5 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 106 Process Heater (H-406). Emission limits and standards for EU H-406 are listed below. Emissions from H-406 are based on a maximum rated capacity (HHV) of 28.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-406	P-107	Process Heater	28.0

NO_X		CO	
lb/hr	TPY	lb/hr	TPY
2.8	12.0	2.3	10.1

a. EU H-406 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-406 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 107 Process Heater (H-601). Emission limits and standards for EU H-601 are listed below. Emissions from H-601 are based on a maximum rated capacity (HHV) of 58.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-601	P-108	Process Heater	58.5

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
5.7	25.1	4.8	21.1	2.0	8.6

a. EU H-601 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-601 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 109 Process Heater (H-901). There are no emission limits established for EU H-901 since this heater is grandfathered but it is limited to the existing equipment as it is. Emissions from H-901 are based on a maximum rated capacity (HHV) of 60.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-901	P-110	Process Heater	60.0

EUG 111 Process Heater for Storage Vessel T-1113 (H-1013). There are no emission limits established for EU H-1013 since this heater is grandfathered but it is limited to the existing equipment as it is. Emissions from H-1013 are based on a maximum rated capacity (HHV) of 2.4 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-1013	P-112	2 Each Process Heaters	2.4, Each

EUG 115 Process Flare (Crude Unit Flare). Emission limits and standards for EU Crude Unit Flare are listed below. Emissions from the Crude Unit Flare are based on a maximum rated capacity (HHV) of 27 MMBTUH, the respective emissions factors from AP-42, Section 13.5 (1/95), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
Crude Unit Flare	P-116	Process Flare	27

NO_X		CO		VOC	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
1.8	8.0	10.0	43.8	3.8	16.6

a. The flare is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
   iii. § 60.106 Test methods and procedures – (e)

b. The flare shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Parts 60 and 63]
   i. The flare shall meet the design requirements of 40 CFR Part 60 NSPS, Subpart A; or
   ii. The flare shall meet the design requirements of 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart A.

EUG 116 Asphalt Blowstill and Thermal Oxidizer (HI-801). Emission limits and standards for EU HI-801 are listed below and are based on a maximum rated auxiliary fuel flow of 12 MMBTUH (HHV), a waste gas flow rate of 21,287 lb/hr with a heat content of 2,363 BTU/lb, and the emissions factors from AP-42, Section 1.4 (7/98). NO_X emissions included a safety factor of 1.5 and a fuel sulfur content based on flow rate of 282,823 SCFH with a nitrogen content of 6.2 ppmdv. SO_2 emissions were based on a flow rate of 282,823 SCFH and a H_2S concentration of 0.1 grain/DSCF.

EU	**Point**	**Description**
HI-801	P-117	Asphalt Blowstill and Thermal Oxidizer

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
9.4	41.1	5.1	22.5	8.0	35.0

a. EU HI-801 is subject to NESHAP, Subpart LLLLL and shall comply with all applicable provisions including but not limited to: [40 CFR Part 63, Subpart LLLLL]
   i. § 63.8681 Am I subject to this subpart? (a-c) & (e)
   ii. § 63.8682 What parts of my plant does this subpart cover? (a), (b)(1), & (e)
   iii. § 63.8683 When must I comply with this subpart? (b)
   iv. § 63.8684 What emission limitations must I meet? (a-b)
   v. § 63.8685 What are my general requirements for complying with this subpart? (a-d)
   vi. § 63.8688 What are my monitoring installation, operation, and maintenance requirements? (a)(1-3), (b)(1-6), (e), & (g)(1-3), & (h-j)
   vii. § 63.8689 How do I demonstrate initial compliance with the emission limitations? (a-c)
   viii. § 63.8690 How do I monitor and collect data to demonstrate continuous compliance? (a-c)

ix. § 63.8691 How do I demonstrate continuous compliance with the operating limits? (a-d)
x. § 63.8692 What notifications must I submit and when? (a-f)
xi. § 63.8693 What reports must I submit and when? (a-f)
xii. § 63.8694 What records must I keep? (a-d)
xiii. § 63.8695 In what form and how long must I keep my records? (a-c)
xiv. § 63.8696 What parts of the General Provisions apply to me?

b. All off-gases from the asphalt blowstill shall be combusted by a properly operated and maintained thermal oxidizer.
c. The temperature of the combustion zone in the Thermal Oxidizer of EU HI-801 shall not drop below 1,260 ºF.
d. The permittee shall monitor and record the temperature at the stack of the Thermal Oxidizer of EU HI-801 (daily).
e. EU HI-801 shall not process more than 21,287 lb/hr of waste gas as determined by site-specific parametric association of waste-gas generation as a function of asphalt throughput and the air flow rate into the asphalt blowing process.
f. The permittee shall monitor and record the asphalt throughput of the blowstill (daily).
g. The permittee shall determine and record the amount of waste gas generated from the asphalt blowstill per barrel of asphalt (quarterly).

EUG 117 Process Heater (H-103). Emission limits and standards for EU H-103 are listed below. Emissions from H-103 are based on a maximum rated capacity (HHV) of 102.6 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-103	P-118	Process Heater	102.6

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
10.1	44.1	8.5	37.0	3.4	15.1

a. EU H-103 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
i. § 60.104 Standards for sulfur dioxide – (a)(1)
ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-103 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 118 Process Heater (H-201). Emission limits and standards for EU H-201 are listed below. Emissions from H-201 are based on a maximum rated capacity (HHV) of 116.7 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF. NO_X emissions from H-201 are based on the factor for post-NSPS units >100 MMBTUH.

EU	Point	Description	MMBTUH
H-201	P-119	Process Heater	116.7

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
21.7	95.2	9.6	42.1	3.9	17.2

a. EU H-201 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Emissions of NO_X from EU H-201 shall not exceed 0.2 lb/MMBTU. [OAC 252:100-33]

c. Fuel use (SCF) and heat content (BTU/SCF) for EU H-201 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 119 Process Heater (H-301). Emission limits and standards for EU H-301 are listed below. Emissions from H-301 are based on a maximum rated capacity (HHV) of 21.6 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-301	P-120	Process Heater	21.6

NO_X		CO	
lb/hr	TPY	lb/hr	TPY
2.1	9.3	1.8	7.8

a. EU H-301 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-301 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 120 Process Heater (H-401A). There are no emission limits for EU H-401A since this process heater is grandfathered but it is limited to the existing equipment as it is. Emissions from H-401A are based on a maximum rated capacity (HHV) of 16.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-401A	P-121	Process Heater	16.0

EUG 121 Process Heater (H-401B). Emission limits and standards for EU H-401B are listed below. Emissions from H-401B are based on a maximum rated capacity (HHV) of 14.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-401B	P-122	Process Heater	14.8

NO_X		CO	
lb/hr	**TPY**	**lb/hr**	**TPY**
1.5	6.4	1.2	5.3

a. EU H-401B is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-401B shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 122 Process Heater (H-402A). There are no emission limits for EU H-402A since this process heater is grandfathered but it is limited to the existing equipment as it is. Emissions from H-402A are based on a maximum rated capacity (HHV) of 13.9 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-402A	P-123	Process Heater	13.9

EUG 123 Process Heater (H-402B). There are no emission limits for EU H-402B since this process heater is grandfathered but it is limited to the existing equipment as it is. Emissions from H-402B are based on a maximum rated capacity (HHV) of 15.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-402B	P-124	Process Heater	15.8

EUG 124 Process Heater (H-407). Emission limits and standards for EU H-407 are listed below. Emissions from H-407 are based on a maximum rated capacity (HHV) of 25.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-407	P-125	Process Heater	25.0

NO_X		CO	
lb/hr	TPY	lb/hr	TPY
2.5	10.7	2.1	9.0

a. EU H-407 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-407 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 125 Boiler (B-801). Emission limits and standards for EU B-801 are listed below. Emissions from B-801 are based on a maximum rated capacity (HHV) of 72.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
B-801	P-126	Boiler	72.5

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
7.1	31.1	6.0	26.2	2.4	10.7

a. EU B-801 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU B-801 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 126 Boiler (B-802). Emission limits and standards for EU B-802 are listed below. Emissions from B-802 are based on a maximum rated capacity (HHV) of 89.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
B-802	P-127	Boiler	89.8

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
8.8	38.6	7.4	32.4	3.0	13.2

a. EU B-802 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. Fuel use (SCF) and heat content (BTU/SCF) for EU B-802 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 127 Boiler (B-803). Emission limits and standards for EU B-803 are listed below. Emissions from B-803 are based on a maximum rated capacity (HHV) of 86.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
B-803	P-128	Boiler	86.8

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
8.5	37.3	7.2	31.3	2.9	12.8

a. EU B-803 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)
b. Fuel use (SCF) and heat content (BTU/SCF) for EU B-803 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 128 Process Heater (H-411). Emission limits and standards for EU H-411 are listed below. Emissions from H-411 are based on a maximum rated capacity (HHV) of 28.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
H-411	P-129	Process Heater	28.0

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2.8	12.0	2.3	10.1	0.9	4.1

a. EU H-411 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)
b. Fuel use (SCF) and heat content (BTU/SCF) for EU H-411 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]
c. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 134 Process Flare (HI-81001). Emission limits and standards for EU HI-81001 are listed below. Emissions from HI-81001 are based on a maximum rated capacity (HHV) of 28 MMBTUH, the respective emissions factors from AP-42, Section 13.5 (1/95), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBUH
HI-81001	P-135	West Flare	28

NO_X		CO		VOC	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
1.9	8.3	10.4	45.4	3.9	17.2

a. EU HI-81001 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
   iii. § 60.106 Test methods and procedures – (e)

b. The flare shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Parts 60 and 63]
   i. The flare shall meet the design requirements of 40 CFR Part 60 NSPS, Subpart A; or
   ii. The flare shall meet the design requirements of 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart A.

EUG 135 Process Heater (H-603). Emission limits and standards for EU H-603 are listed below. Emissions from H-603 are based on a maximum rated capacity (HHV) of 125.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X and CO which are based on the following emission factors: 0.066 and 0.0415 lb/MMBTU, respectively.

EU	Point	Description	MMBTUH
H-603	P-136	Process Heater	125.5

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
8.3	36.3	5.2	22.8	4.2	18.5

a. EU H-603 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. H-603 shall be operated with LNB. [OAC 252:100-8-34]

c. Emissions of NO_X from EU H-603 shall not exceed 0.066 lb/MMBTU. [OAC 252:100-8-34]

d. Emissions of CO from EU H-603 shall not exceed 0.0415 lb/MMBTU. [OAC 252:100-8-34]

e. Fuel use (SCF) and heat content (BTU/SCF) for EU H-603 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

f. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 136 Process Heater (H-6501). Emission limits and standards for EU H-6501 are listed below. Emissions from H-6501 are based on a maximum rated capacity (HHV) of 92.1 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X and CO which are based on the following emission factors: 0.060 and 0.0404 lb/MMBTU, respectively.

EU	**Point**	**Description**	**MMBTUH**
H-6501	P-137	Process Heater	92.1

NO_X		**CO**		**SO_2**	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
5.5	24.2	3.7	16.3	3.1	13.5

a. EU H-6501 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. H-6501 shall be operated with LNB. [OAC 252:100-8-34]

c. Emissions of NO_X from EU H-6501 shall not exceed 0.060 lb/MMBTU. [OAC 252:100-8-34]

d. Emissions of CO from EU H-6501 shall not exceed 0.0404 lb/MMBTU. [OAC 252:100-8-34]

e. Fuel use (SCF) and heat content (BTU/SCF) for EU H-6501 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

f. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 137 Process Heater (H-6502). Emission limits and standards for EU H-6502 are listed below. Emissions from H-6502 are based on a maximum rated capacity (HHV) of 54.3 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X and CO which are based on the following emission factors: 0.060 and 0.0404 lb/MMBTU, respectively.

EU	Point	Description	MMBTUH
H-6502	P-138	Process Heater	54.3

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
3.3	14.3	2.2	9.6	1.8	8.0

a. EU H-6502 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. H-6502 shall be operated with LNB. [OAC 252:100-8-34]

c. Emissions of NO_X from EU H-6502 shall not exceed 0.060 lb/MMBTU. [OAC 252:100-8-34]

d. Emissions of CO from EU H-6502 shall not exceed 0.0404 lb/MMBTU. [OAC 252:100-8-34]

e. Fuel use (SCF) and heat content (BTU/SCF) for EU H-6502 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

f. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 138 Process Heater (H-15001). Emission limits and standards for EU H-15001 are listed below. Emissions from H-15001 are based on a maximum rated capacity (HHV) of 326.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X and CO which were based on an emission factor of 0.06 lb/MMBTU and 0.030 lb/MMBTU, respectively.

EU	Point	Description	MMBTUH
H-15001	P-139	Process Heater	326.8

NO_X		CO		PM_{10}		SO_2		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
19.6	85.9	9.8	42.9	2.4	10.7	10.8	47.2	1.8	7.7

a. EU H-15001 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
[40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU H-15001 shall be operated with LNB. [OAC 252:100-8-34]

c. Emissions of NO_X from EU H-15001 shall not exceed 0.06 lb/MMBTU. [OAC 252:100-8-34]

d. Emissions of CO from EU H-15001 shall not exceed 0.030 lb/MMBTU. [OAC 252:100-8-34]

e. Fuel use (SCF) and heat content (BTU/SCF) for EU H-15001 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

f. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and results from the most recent stack tests. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 139 Process Heater (H-210001). Emission limits and standards for EU H-210001 are listed below. Emissions from H-210001 are based on a maximum rated capacity (HHV) of 12.2 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.025 grains/DSCF.

EU	Point	Description	MMBTUH
H-210001	P-140	Process Heater	12.2

NO_X	
lb/hr	TPY
1.2	5.2

a. EU H-210001 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU H-210001 is subject to NSPS, Subpart Dc and shall comply with all applicable requirements including but not limited to: [40 CFR Part 60, Subpart Dc]
   i. The permittee shall record and maintain records of the fuels combusted in EU H-210001 during each calendar month. [40 CFR 60.48c(g)]

c. EU H-210001 shall only be fired with commercial grade natural gas. [OAC 252:100-31]

EUG 140 Gasoline Loading Rack Vapor Combustor (Light Products Loading Terminal). Emission limits and standards for the Light Products Loading Terminal are listed below. Emissions from the Light Products Loading Terminal Vapor Combustor are based on the following: an hourly loading limit of 155,782 gallons/hour of gasoline/diesel; an annual loading limit of 22,525,714 bbl/yr of gasoline/diesel; and the following factors: VOC and CO: 10 mg/L loaded; NO_X: 4 mg/L loaded. Fugitive VOC emissions from the Light Products Loading Terminal are based on calculated loading losses and a 99.2% collection efficiency for gasoline.

EU	Point
Light Products Loading Terminal (LPLT)	P-141

	NO_X		CO		VOC	
Source	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Vapor Combustor	5.2	15.8	13.0	39.5	17.2	39.5

a. The amount of gasoline and diesel loaded at the LPLT shall not exceed 155,782 gallons/hr based on a daily average or 22,525,714 bbl/year based on a 12-month rolling total.
[OAC 252:100-8-6(a)(3)]

b. The LPLT vapor combustor is subject to NSPS, Subpart J is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to:
[40 CFR Part 60, Subpart J]

i. § 60.104 Standards for sulfur dioxide – (a)(1)

ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.

iii. § 60.106 Test methods and procedures – (e)

c. The LPLT vapor combustor shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Part 63]

i. The vapor combustor shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.

d. The LPLT is subject to NESHAP, 40 CFR Part 63, Subpart CC and shall comply with all applicable requirements including but not limited to: [40 CFR 63, NESHAP, Subpart CC]

i. § 63.642 General Standards.

ii. § 63.650 Gasoline Loading Rack Provisions.

iii. § 63.654 Reporting and Recordkeeping Requirements.

EUG 141* FCCU Flue Gas Scrubber (FGS-200). Emission limits and standards for EU FGS-200 are listed below. Emissions from the FGS are based on a BACT analysis and a supplemental environmental project.

EU	Point	Description
FGS-200	P-142	FCCU No. 1 Regenerator/CO Boiler and FCCU No. 2 Regenerator

***** - EUGs 141A, 141B, and 141C, will all be vented to this EUG and point upon completion of the modifications. EUG 145 will either be vented to this EUG or another wet scrubber.

	NO_X		CO		PM_{10}*		SO_2	
Scenario	**lb/hr**	**TPY****	**lb/hr**	**TPY****	**lb/hr**	**TPY****	**lb/hr**	**TPY****
1	118.0	344.8	178.1	234.7	22.4	51.3	66.4	223.6
2	118.0	344.8	178.1	234.7	26.2	53.2	66.4	223.6

* - The PM_{10} emission limits are based only on the front-half of the PM_{10} sampling train.

** - Based on a 12-month rolling average.

1 - Represents emissions from the FCCU Flue Gas Scrubber (FGS-200) without the FCCU Catalyst Hoppers Vent (cat-hop) being vented to the FCCU Flue Gas Scrubber (FGS-200).

2 - Represents emissions from FCCU Flue Gas Scrubber (FGS-200) with the FCCU Catalyst Hoppers Vent (cat-hop) being vented to the FCCU Flue Gas Scrubber (FGS-200).

a. The new and existing CO Boilers shall be operated with LNB. [OAC 252:100-8-34]
b. EU FGS-200 shall be equipped with a continuous emissions monitoring system (CEMS) for determining and recording NO_X emissions. The CEMS shall meet the applicable performance specifications of 40 CFR Part 60, Appendix B. [OAC 252:100-8-6(a)(3)]
c. The permittee shall compute the 12-month rolling total NO_X emissions from EU FGS-200 using the monthly average monitored NO_X concentrations along with the monthly average dry-basis stack gas flow rate.
d. The off-gases from the FCCU No. 1 Regenerator shall be combusted in a CO Boiler prior to being processed by the FGS to reduce emissions of CO. [OAC 252:100-8-34]
e. The emissions of CO from the FCCU No. 1 Regenerator shall be reduced by use of complete secondary combustion of the waste gas generated. [OAC 252:100-35-2(b)]
    i. Emissions of CO from the FCCU No. 1 Regenerator shall be vented to and completely combusted in the CO Boiler.
f. The FCCU No. 1 Regenerator's existing CO Boiler and Incinerator shall be replaced by a new CO Boiler capable of handling all of the FCCU No. 1 Regenerator off-gases. The existing FCCU No. 1 Regenerator's CO Boiler shall be retrofitted with LNB and maintained in standby or limited supplemental service. The FCCU No. 1 Regenerator's existing Incinerator shall be decommissioned. [CO 02-007 (IV)(4)(B)]
g. The FCCU No. 2 Regenerator shall be operated in full combustion regeneration mode to reduce emissions of CO. [OAC 252:100-8-34 & 100-35-2(b)]
h. EU FGS-200 shall be equipped with a CEMS for determining and recording CO emissions. [OAC 252:100-8-6(a)(3)]
i. The permittee shall compute the 12-month rolling total CO emissions from EU FGS-200 using the monthly average monitored CO concentrations along with the monthly average dry-basis stack gas flow rate.
j. All off-gases from the FCCU No. 1 Regenerator/CO Boiler system and the FCCU No. 2 Regenerator shall be treated by a Wet Scrubber (WS) to control emissions of SO_2 from the FCCU. [OAC 252:100-8-34]
    i. The WS shall be designed and operated with devices that reduce the amount of entrained water in the WS off-gases.
k. EU FGS-200 shall be equipped with a CEMS for determining and recording SO_2 emissions. [OAC 252:100-8-6(a)(3)]
l. The permittee shall compute the 12-month rolling total SO_2 emissions from EU FGS-200 using the monthly average monitored SO_2 concentrations along with the monthly average dry-basis stack gas flow rate.
m. The FCCU No. 1 Regenerator shall be operated with dual cyclones and the FCCU No. 2 Regenerator shall be operated with tertiary cyclones. The cyclones are within the Regenerators and shall be used to reduce emissions of PM_{10}. [OAC 252:100-34]
n. The permittee shall install monitors to continuously monitor and record the following parameters of the WS:
    i. Liquid flow rate of the WS (24-hour average).
    ii. Gas temperature and flow rate through the WS (24-hour average).
    iii. Liquid to Gas Ratio of the WS (24-hour average).
    iv. Pressure drop across the WS (24-hour average).
    v. pH of the WS liquor (24-hour average).

vi. These parameters are parametric indicators of the WS desired control efficiency. The indicator ranges for these parameters shall be determined based on actual performance tests data established during the initial performance tests to determine the WS control efficiency. Monitored operating parameters may be adjusted (flow rate, pressure drop, or liquid-to-gas ratio) from the average of measured values during the performance test to a maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using additional performance tests or control device design specifications and manufacturer recommendations in conjunction with an engineering assessment. The permittee shall provide supporting documentation and rationale demonstrating to the satisfaction of the AQD, that the FCCU Flue Gas Scrubber complies with all applicable emission limits at the proposed operating limits.

vii. The permittee may request to monitor alternative parameters than those listed above. The request to monitor alternative parameters shall be submitted for review and approval or disapproval to the AQD. The request shall include the following information:

A. The parameter(s) to be monitored to establish compliance of the FCCU Flue Gas Scrubber with all applicable emission limitations;

B. A justification for the alternative monitoring parameter(s) and all supporting information used to determine that the selected alternative monitoring parameter(s) will demonstrate compliance with the applicable emission limitations;

C. A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine the FCCU Flue Gas Scrubber will continuously comply with all applicable emission limitations and the schedule for this demonstration. The permittee shall certify that an operating limitation will be established for the monitored parameter(s) that represents the conditions of the WS when it is being properly operated and maintained to meet the applicable emission limitations;

D. If monitoring and recording are not continuous, the frequency and content of the monitoring, recordkeeping, and reporting. The permittee shall also include the rationale for the proposed monitoring, recordkeeping, and reporting requirements; and

E. Averaging time for the alternative operating parameter(s).

viii. The gas flow rate can be determined through the use of other parametric indicators such as regenerator flowrates based on coke production and combustion, flue-gas CO_2 concentration and flue-gas O_2 concentration, daily regenerator flue gas analysis's, CO boiler combustion calculations, and other parameters that may be monitored.

o. The FCCU is subject to NSPS, 40 CFR Part 60, Subpart J and shall comply with all applicable requirements including but not limited to: [40 CFR 60, NSPS, Subpart J]

i. §60.102 Standard for particulate matter.

ii. §60.103 Standard for carbon monoxide.

iii. §60.104 Standard for sulfur oxides – (b-d).

iv. §60.105 Monitoring of emissions and operations – (a)(1), (a)(2), (a)(8-13), (c), (d), (e)(1), and (e)(2) or other alternative monitoring approved per § 60.13.
v. §60.106 Test Methods and Procedures (a-d) and (g-k).
vi. §60.107 Reporting and Recordkeeping Requirements (a-f).
vii. §60.108 Performance Test and Compliance Provisions (a-e).

p. EU FGS-200 is subject to NESHAP, Subpart UUU and shall comply with all applicable including but not limited to: [40 CFR Part 63, Subpart UUU]
i. § 63.1560 What is the purpose of this subpart?
ii. § 63.1561 Am I subject to this subpart?
iii. § 63.1562 What parts of my plant are covered by this subpart?
iv. § 63.1563 When do I have to comply with this subpart?
v. § 63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?
vi. § 63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?
vii. § 63.1569 What are my requirements for HAP emissions from bypass lines?
viii. § 63.1570 What are my general requirements for complying with this subpart?
ix. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
x. § 63.1574 What notifications must I submit and when?
xi. § 63.1575 What reports must I submit and when?
xii. § 63.1576 What records must I keep, in what form, and for how long?
xiii. § 63.1577 What parts of the General Provisions apply to me?

EUG 141A FCCU No. 1 Regenerator and CO Boiler/Incinerator (HI-251). The FCCU No. 1 Regenerator and CO Boiler will be vented to the WS and all emissions are associated with EU FGS-200. The FCCU No. 1 Incinerator will be decommissioned.

EU	Point	Description
HI-251	P-143	FCCU No. 1 Regenerator and CO Boiler/Incinerator

a. All emissions from the FCCU No. 1 Regenerator shall be processed through a CO Boiler (EU B-253 and/or B-254) and then vented through the EU FGS-200. [OAC 252:100-8-34]
b. The FCCU No. 1 Incinerator shall be decommissioned. [CO 02-007 (IV)(4)(B)]

EUG 141B CO Boilers (B-253 and B-254). The CO Boilers are vented to the WS and all emissions are associated with EU FGS-200.

EU	Point	Description	MMBTUH
B-253	P-143	CO Boiler	144.0
B-254	P-143	Boiler/CO Boiler	144.0

a. The CO Boilers shall be vented to the FCCU WS. [OAC 252:100-8-34]
b. The CO Boilers shall be equipped with LNB or ULNB. [OAC 252:100-8-34]
c. All emissions from the FCCU No. 1 Regenerator shall be processed through EU B-253 and/or B-254.
d. EU B-253 and B-254 are subject to NSPS, Subpart J and shall comply with all applicable requirements including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)
e. EU B-253 and B-254 are subject to NSPS, Subpart Db and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart Db]
   i. § 60.44b Standard for Nitrogen Oxides – (h), (i), and (l)(1) or (l)(2);
   ii. § 60.46b Compliance and Performance Test Methods and Procedures for Nitrogen Oxides – (c) and (e)(1), (e)(4), (f)(1), or (f)(2);
   iii. § 60.48b Emission monitoring for Nitrogen Oxides – (h);
   iv. § 60.49b Reporting and Recordkeeping Requirements – (a)(1), (a)(3), (b), (d), (g)(1), (g)(5), (h)(2)(i), (h)(4), (o), (w), (v).
f. Emissions of NO_X from EU B-253 shall not exceed 0.03 lb/MMBTU. [OAC 252:100-33]
g. Emissions of NO_X from EU B-254 shall not exceed 0.06 lb/MMBTU. [OAC 252:100-33]

EUG 141C FCCU No. 2 Regenerator (R-251). The FCCU No. 2 Regenerator is vented to the WS and all emissions are associated with EU FGS-200.

EU	Point	Description
R-251	P-142	FCCU No. 2 Regenerator

a. The FCCU No. 2 Regenerator shall be operated in full combustion regeneration mode. [OAC 252:100-8-34 & 100-35-2(b)]
b. The FCCU No. 2 Regenerator shall be vented to the FCCU WS. [OAC 252:100-8-34]

EUG 142 #1 SRU Incinerator EU HI-501. Emission limits for the #1 SRU Incinerator. NO_X, CO, VOC, and PM_{10} emissions from the incinerator are based on combustion of 8.2 MMBTUH of auxiliary fuel, combustion of 217,512 SCFH of waste gas with a heat content of 23 BTU/SCF, and AP-42, Section 1.4 (7/98). SO_2 emissions are based on a flow rate of 288,212 DSCFH @ 0% O_2 and the NSPS, Subpart J, SO_2 emission limit of 250 ppmdv.

EU	Point	Description	MMBTUH
HI-501	P-144	SRU Incinerator	13.2

NO_X		SO_2	
lb/hr	TPY	lb/hr	TPY
1.9	8.5	12.0[1]	52.5

1 – 2-hour average of contiguous 1-hour averages.

a. The SRU shall be equipped with a tail gas-treating unit (TGTU). The TGTU shall process the off-gases from the SRU. [OAC 252:100-8-6(a)(1)]

b. EU H-501 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(2)(i);
   ii. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
   iii. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).

c. EU H-501 is subject to NESHAP, Subpart UUU and shall comply with all applicable provisions by the dates specified in § 63.1563(b). [40 CFR Part 63, Subpart UUU]
   i. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1), (b)(1, 3, 4, 5, 6, & 7), & (c)(1 & 2);
   ii. § 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
   iii. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
   iv. 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
   v. 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
   vi. 63.1574 What notifications must I submit and when? – (a)(2) & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
   vii. 63.1575 What reports must I submit and when? – (a-h);
   viii. 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
   ix. 63.1577 What parts of the General Provisions apply to me?

d. EU H-501 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions including but not limited to: [OAC 252:100-31-26]
   i. H_2S from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to sulfur dioxide. H_2S emissions shall be reduced by a minimum of 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]
   ii. Sulfur recovery plants operating in conjunction with any refinery process shall have the sulfur reduction efficiencies required below. [OAC 252:100-31-26(a)(2)(B)]
      A. When the sulfur content of the acid gas stream from the refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the required sulfur dioxide emission reduction efficiency of the sulfur recovery plant shall be calculated using the following formula where Z is the minimum emission reduction efficiency required at all times and X is the sulfur feed rate expressed in LT/D of sulfur rounded to one decimal place: $Z = 92.34 (X^{0.00774})$ [OAC 252:100-31-26(a)(2)(D)]
   iii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal non-combustion of the gas. [OAC 252:100-31-26(c)]

EUG 143 Emergency Generators (EEQ-8801 and EEQ-80001). Limits for EU EEQ-8801 and EEQ-80001 are listed below. Emissions from the emergency generators were based on 800 hours of operation a year, a diesel fuel heating value of 19,500 BTU/lb, a fuel sulfur content of 0.05% by weight, and the following:

EEQ-8801 - A maximum fuel input of 461.5 lb/hr and the respective emissions factors from AP-42, Section 3.3 (10/96);

EEQ-80001 - A maximum fuel input of 106.5 lb/hr and the respective emissions factors from AP-42, Section 3.4 (10/96).

EU	Point	Make/Model	KW	Serial #
EEQ-8801	P-145	DMT/DMT-825D2	750	93447-1
EEQ-80001	P-146	Cummins/6BT5.9G-2	80	45555233

a. EU EEQ-8801 and EEQ-80001 shall not operate more than 800 hours per year except for emergencies, each based on a 12-month rolling total.
b. EU EEQ-8801 and EEQ-80001 shall be fitted with non-resettable hour-meters.
c. The permittee shall record the number of hours each engine is operated each month.
d. The sulfur content of the fuel for EU EEQ-8801 and EEQ-80001 shall not exceed 0.05% by weight (on-road low-sulfur diesel performance specification). [OAC 252:100-31]
e. The permittee shall maintain records of the diesel fuel purchase receipts documenting the sulfur content for each delivery of diesel fuel or shall determine and record the fuel sulfur content for each delivery of diesel fuel for the generators. [OAC 252:100-45]
f. A serial number or another acceptable form of permanent (non-removable) identification shall be on each generator.

EUG 144 Alternate Flares. There are no emission limits for these flares since they are grandfathered but they are limited to the existing equipment as it is. Emissions from the flares were based on the maximum rated capacities (HHV) of the flares, the respective emissions factors from AP-42, Section 13.5 (1/95), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	Point	Description	MMBTUH
altfl	P-147	Alternate Crude Unit Flare	27
altfl	P-148	Alternate Alkylation Unit Flare	28

EUG 145 FCCU Catalyst Hopper Vent (cat_hop). Emissions limits for the FCCU Catalyst Hoppers are based on venting emissions to a WS or equally effective control device.

EU	Point	Description
cat_hop	P-149	FCCU Catalyst Hopper Vent

	PM_{10}*	
Scenario	**lb/hr**	**TPY****
1	3.8	1.9
2	0.0	0.0

* - The PM_{10} emission limits are based only on the front-half of the PM_{10} sampling train.
** - Based on a 12-month rolling average.
1 - Represents emissions from the FCCU Catalyst Hoppers Vent (cat-hop) without the FCCU Catalyst Hoppers Vent (cat-hop) being vented to the FCCU Flue Gas Scrubber (FGS-200).
2 - Represents emissions from the FCCU Catalyst Hoppers Vent (cat-hop) with the FCCU Catalyst Hoppers Vent (cat-hop) being vented to the FCCU Flue Gas Scrubber (FGS-200).

a. The FCCU Catalyst Hoppers shall be vented through a cyclone and then to the FCCU WS (FGS-200) or another equally effective control device. [OAC 252:100-8-34]
b. If the permittee does not vent the FCCU Catalyst Hoppers to the FCCU WS, the permittee shall monitor and record the following parameters of the WS or other parameters as necessary to ensure compliance with the emission limit above:
   i. Liquid flow rate of the WS (24-hour average).
   ii. Pressure drop across the WS (24-hour average).
   iii. These parameters are parametric indicators of the WS desired control efficiency. The indicator ranges for these parameters shall be determined based on actual performance tests data established during the initial performance tests to determine the WS control efficiency.

EUG 146 Platformer Catalyst Regeneration Vent (CCR). Emission limits and standards for EU CCR are listed below. Emissions from the CCR are based on a coke-burning rate of 70 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 1,000 lb/hr and a coke combustion rate of 7% of the catalyst processing rate (1,000 lb/hr @ 7% wt), with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on the following emissions factors from AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion: NO_X - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom); CO - 5 lb/ton of coke combusted (Spreader Stoker); PM_{10} - 13.2 lb/ton of coke combusted (Spreader Stoker) & 0.07 lb/hr catalyst; SO_2 - 38 x (Sulfur Content) lb/ton of coke combusted (Spreader Stoker); VOC - 1.3 lb/ton of coke combusted (Underfeed Stoker). PM_{10} emissions also include a recovery factor for the catalyst of 99.99%.

EU	Point	Description
CCR	P-150	Platformer Catalyst Regeneration Combustion Vent

NO_X		CO	
lb/hr	**TPY**	**lb/hr**	**TPY**
1.2	5.2	0.4	1.9

a. The catalyst recirculation rate shall not exceed 1,000 lb/hr. [OAC 252:100-8-6(a)(1)]

b. The CCR shall be operated in full combustion regeneration mode to reduce emissions of CO to at least 0.44 lb/hr. [OAC 252:100-35-2(b)]

   i. At least once per calendar quarter, the permittee shall conduct tests of CO emissions in the exhaust gases from the CCR when operating under representative conditions. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD Portable Analyzer Guidance document, or an equivalent method approved by Air Quality. When four consecutive quarterly tests show compliance with the CO emission limit, the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test.Upon any showing of non-compliance with emissions limitations, the testing frequency shall revert to quarterly.

c. The sulfur content of the Platformer feed shall not exceed 5% by weight based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]

d. EU CCR is subject to NESHAP, Subpart UUU and shall comply with all applicable including but not limited to: [40 CFR Part 63, Subpart UUU]

   i. § 63.1560 What is the purpose of this subpart?
   ii. § 63.1561 Am I subject to this subpart?
   iii. § 63.1562 What parts of my plant are covered by this subpart?
   iv. § 63.1563 When do I have to comply with this subpart?
   v. § 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?
   vi. § 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?
   vii. § 63.1569 What are my requirements for HAP emissions from bypass lines?
   viii. § 63.1570 What are my general requirements for complying with this subpart?
   ix. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
   x. § 63.1574 What notifications must I submit and when?
   xi. § 63.1575 What reports must I submit and when?
   xii. § 63.1576 What records must I keep, in what form, and for how long?
   xiii. § 63.1577 What parts of the General Provisions apply to me?

EUG 147 Instrument/Plant Air Compressor (C-80018). Emission limits and standards for EU C-80018 are listed below. Emissions from C-80018 are based on 4,000 hours of operation a year, a horsepower rating of 450-hp, the respective emissions factors from AP-42, Section 3.3 (10/96), and a fuel sulfur content of 0.05% by weight.

EU	Point	Make/Model	Hp
C-80018	P-151	Detroit Diesel/8V-92TA	450

NO_X		CO	
lb/hr	**TPY**	**lb/hr**	**TPY**
14.0	27.9	3.0	6.0

a. EU C-80018 shall not operate more than 4,000 hours per year based on a 12-month rolling total.
b. EU C-80018 shall be fitted with a non-resettable hour-meter.
c. The permittee shall record the number of hours each engine is operated each month.
d. The sulfur content of the fuel for EU C-80018 shall not exceed 0.05% by weight. (on-road low-sulfur diesel performance specification) [OAC 252:100-31]
e. The permittee shall maintain records of the diesel fuel purchase receipts documenting the sulfur content for each delivery of diesel fuel or shall determine and record the fuel sulfur content for each delivery of diesel fuel for the Instrument/Plant Air Compressor. [OAC 252:100-45]
f. EU C-80018 shall be equipped a with permanent (non-removable) identification such as a serial number or another acceptable form of identification.
g. Placement of EU C-80018 shall be limited to the north end of the FCCU area. [OAC 252:100-3]

EUG 148 Process Heater (H-100024). Limits for EU H-100024 are listed below. Emissions from H-100024 were based on a maximum rated capacity (HHV) of 13.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF and actual emissions are considered insignificant (<5 TPY).

EU	Point	Description	MMBTUH
H-100024	P-152	Asphalt Tank Heater	13.5

a. EU H-100024 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)
b. EU H-100024 is subject to NSPS, Subpart Dc and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart Dc]
   i. The permittee shall record and maintain records of the fuels combusted in EU H-100024 during each calendar month. [40 CFR 60.48c(g)]

EUG 168 Storage Vessel T-1155. Emissions from EU T-1155 are based on a throughput of 12,045,000 BPY and actual emissions are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1155	P-168	External Floating	Heavy Naphtha/Distillate	163,555

a. The permittee shall comply with the applicable sections of NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel except as provided in NESHAP, 40 CFR Part 63, § 63.640(n)(8)(i) through (vi):
   i. §60.112b (a)(2) Standards for VOC;
   ii. §60.113b (b) Testing and Procedures;
   iii. §60.115b (b) Recordkeeping and Reporting Requirements; and
   iv. §60.116b Monitoring of Operations.

b. The storage vessel shall not store a VOC with vapor pressure (VP) greater than or equal to 11.1 psia under actual storage conditions.

EUG 169 Storage Vessel T-156. Emissions from EU T-156 are based on a throughput of 442,319 bbl/yr and a maximum liquid bulk temperature of 200 ºF and actual emissions are considered insignificant t (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-156	P-169	Cone	FCCU Slurry/Fuel Oil No. 6	56,000

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to:
   i. § 60.116b Monitoring of Operations – (a) & (b).
   ii. The storage vessel shall not store a VOL with a MTVP greater than or equal to 0.5076 psia.
   iii. The permittee shall determine, using the methods specified in § 60.116(b), and maintain a record of the MTVP of the VOL stored in the storage vessel.

b. The temperature of the liquid shall not exceed 200 ºF. [OAC 252:100-8-6(a)(1)]

c. The temperature of the liquid shall be measured and recorded at least once daily. [OAC 252:100-8-6(a)(3)]

EUG 170 #2 SRU Incinerator. Emission limits for the SRU Incinerator. NO_X, CO, VOC, and PM_{10} emissions from the incinerator are based on combustion of 27.7 MMBTUH of auxiliary fuel, combustion of 552,396 SCFH of waste gas with a heat content of 23 BTU/SCF, and AP-42, Section 1.4 (7/98). SO_2 emissions are based on a flow rate of 630,000 DSCFH @ 0% O_2 and the NSPS, Subpart J, SO_2 emission limit of 250 ppmdv.

EU	Point	Description	MMBTUH
H-5601	P-170	SRU Incinerator	40.4

NO_X		SO_2	
lb/hr	TPY	lb/hr	TPY
4.0	17.4	26.2[1]	114.7

[1] – 2-hour average of contiguous 1-hour averages.

a. The permittee shall incorporate the following BACT for reduction of SO_2 emissions. [OAC 252:100-8-6(a)]
   i. The SRU shall be equipped with a tail gas treating unit (TGTU). The TGTU shall process the off-gases from the SRU.

b. EU H-5601 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide (SO_2) – (a)(2)(i);
   ii. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
   iii. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).

c. EU H-5601 is subject to NESHAP, Subpart UUU and shall comply with all applicable provisions including but not limited to: [40 CFR Part 63, Subpart UUU]
   i. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1)(i), (b)(1, 2, 5, 6, & 7), & (c)(1 & 2);
   ii. § 60.105 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
   iii. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
   iv. 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
   v. 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
   vi. 63.1574 What notifications must I submit and when? – (a)(1-3), (c), (d), & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
   vii. 63.1575 What reports must I submit and when? – (a-h);
   viii. 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
   ix. 63.1577 What parts of the General Provisions apply to me?

d. EU H-5601 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]
   i. Hydrogen sulfide (H_2S) from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to SO_2. H_2S emissions shall be reduced by a minimum of 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]
   ii. Sulfur recovery plants operating in conjunction with any refinery process shall have the sulfur reduction efficiencies required below. [OAC 252:100-31-26(a)(2)(B)]
      A. When the sulfur content of the acid gas stream from the refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the required SO_2 emission reduction efficiency of the sulfur recovery plant shall be calculated using the following formula where Z is the minimum emission reduction efficiency required at all times and X is the sulfur feed rate expressed in LT/D of sulfur rounded to one decimal place: $Z = 92.34\ (X^{0.00774})$ [OAC 252:100-31-26(a)(2)(D)]
   iii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 171 Hot Oil Heater (H-5602). Limits for EU H-5602 are listed below. Emissions from H-5602 were based on a maximum rated capacity (HHV) of 20 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF.

EU	**Point**	**Description**	**MMBTUH**
H-5602	P-171	Hot Oil Heater	20.0

a. EU H-5602 is subject to NSPS, Subpart Dc and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart Dc]
   i. The permittee shall record and maintain records of the fuels combusted in EU H-5602 during each calendar month. [40 CFR 60.48c(g)]

b. EU H-5602 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).

c. EU H-5602 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.05 lb/MMBTU.

d. EU H-5602 is subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions including but not limited to: [40 CFR Part 63, Subpart DDDDD]
   i. § 63.7495 When do I have to comply with this subpart? - (a) & (d)
   ii. § 63.7500 What emission limits, work practice standards, and operating limits must I meet? - (a)(1)
   iii. § 63.7505 What are my general requirements for complying with this subpart? - (a), (b), (d) & (e)
   iv. § 63.7510 What are my initial compliance requirements and by what date must I conduct them? - (a), (c), (e) & (g)
   v. § 63.7515 When must I conduct subsequent performance tests or fuel analyses? - (a), (e) & (g)
   vi. § 63.7520 What performance tests and procedures must I use? - (a), (b), (d), & (e-g)
   vii. § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards? - (a)& (e)
   viii. § 63.7535 How do I monitor and collect data to demonstrate continuous compliance? (a) & (c)
   ix. § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards? - (a), (b), (c) & (d)
   x. § 63.7545 What notifications must I submit and when? - (a), (c), (d) & (e)
   xi. § 63.7550 What reports must I submit and when? - (a), (b), (c), (d), (e) & (g)
   xii. § 63.7555 What records must I keep? - (a) & (d)
   xiii. § 63.7560 In what form and how long must I keep my records? - (a), (b) & (c)
   xiv. § 63.7565 What parts of the General Provisions apply to me?

EUG 172 Regenerated Amine Storage Vessel (TK-5801). Emissions from EU TK-5801 are based on TANKS4.0, a throughput of 12,463,046 BPY, and a H_2S concentration of 0.1% by weight and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
TK-5801	P-172	Cone	Amine	895

EUG 173 Liquid Sulfur Storage Vessel (TK-5602). Emissions from EU TK-5602 are based on a H_2S concentration of 8,000 ppmv, a run-down rate of 12,100 lb/hr of molten sulfur (130 LTD), and the density of molten sulfur (124.8 lb/CF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2.

EU	Point	Roof Type	Contents	Barrels
TK-5602	P-173	Cone	Sulfur	3,644

a. EU TK-5602 shall be vented to the SRU incinerator or the input of the SRU at all times. [OAC 252:100-8-6(a)(1)]

b. EU TK-5602 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]

   i. H_2S from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to SO_2. H_2S emissions shall be reduced by a minimum of 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]

   ii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 174 Molten Sulfur Railcar Loading Rack (LR-SB001). Emissions from EU LR-SB001 are based on a H_2S concentration of 8,000 ppmv, a loading rate of 100,000 lb/hr of molten sulfur, and the density of molten sulfur (124.8 lb/CF).

EU	Point	Loading Rack	Loading Arm
LR-SB001	P-171	1	1
			2
			3

a. Emissions of H_2S from EU LR-SB001 shall not exceed 0.3 lb/hr based on a 2-hour average. Compliance shall be determined using the loading rate and the H_2S concentration of the gases coming from the railcars. The H_2S concentration shall be determined at least quarterly using stain tubes. [OAC 252:100-31-26(b)(1)]

EUG 175 Wastewater Treatment Plant (WWTP) Incinerator. Emission limits for the WWTP Incinerator. Emissions from HI-8801 are based on a maximum rated auxiliary fuel flow of 15 MMBTUH (HHV), a flow rate of 198,000 SCFH (42 lb/hr) with a heat content of 21,344 BTU/lb, a nitrogen content of 315 ppmdv, a H_2S concentration of 0.1 grain/DSCF and a combustion efficiency of 95%, and the emissions factors from AP-42, Section 1.4 (7/98), except for emissions of NO_X, which are based on an emission factor of 0.12 lb/MMBTU.

EU	**Point**	Description	**MMBTUH**
HI-8801	P-176	WWTP Incinerator	15.9

NO_X		**CO**		**SO_2**		**VOC**	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
8.9	39.0	1.3	5.7	5.8	25.5	2.2	9.7

a. EU HI-8801 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. All off-gases from the WWTP Bioreactors shall be combusted by a properly operated and maintained thermal oxidizer.

c. The temperature of the combustion zone in the Thermal Oxidizer of EU HI-8801 shall not drop below 1,100 ºF.

d. The permittee shall continuously monitor and record the temperature of the combustion zone of the Thermal Oxidizer of EU HI-8801 (daily average).

e. EU HI-8801 shall not process more than 198,000 SCF/hr of waste gas based on a weekly or monthly average as specified in accordance with paragraph (h) as determined by site-specific parametric association of waste-gas generation as a function of air flow rate into the bioreactors.

f. The ammonia concentration of the waste gases vented to the WWTP Incinerator shall not exceed 315 ppmv based on a weekly or monthly average as specified in accordance with paragraph (h).

g. The facility shall determine and record weekly the ammonia concentration and flow of the waste gases vented to the WWTP Incinerator. If four consecutive weekly tests are in compliance with the ammonia and flow limitations, the testing and calculation frequency may be reduced to monthly testing and calculations. Upon any showing of non-compliance with the ammonia concentration or flow limitations, the testing and calculation frequency shall revert to weekly.

h. Compliance with the emission limitations shall be based on the fuel and waste gas combustion, fuel and waste gas heat content, waste gas ammonia concentrations, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 176 #1 SRU Sulfur Storage Pit (SSP-520). Emissions from EU SSP-520 are based on a H_2S concentration of 8,000 ppmv, a run-down rate of 10,908 lb/hr of molten sulfur (119 LTD), and the density of molten sulfur (124.8 lb/CF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2.

EU	Point	Contents
SSP-520	SSP-520	Sulfur

a. The throughput for EU SSP-520 shall not exceed 119 LTD based on a 365-day rolling average. [OAC 252:100-8-6(a)(1)]

b. Records of throughput shall be maintained (monthly and 12-month rolling average). [OAC 252:100-8-6(a)(3)]

b. EU SSP-520 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]

   i. H_2S from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to SO_2. H_2S emissions shall be reduced by a minimum of 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]

   ii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 177 #1 SRU Molten Sulfur Railcar Loading Arm (MSLA-520). Emissions from EU MSLA-520 are based on a H_2S concentration of 8,000 ppmv, a loading rate of 100,000 lb/hr of molten sulfur, and the density of molten sulfur (124.8 lb/CF).

EU	Point	Loading Rack	Loading Arm
MSLA-520	MSLA-520	1	1

a. EU MSLA-520 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]

   i. Emissions of H_2S from the loading operation shall not exceed 0.3 lb/hr based on a 2-hour average. Compliance shall be determined using the loading rate and the H_2S concentration of the gases coming from the loading operation. The H_2S concentration shall be determined at least once monthly using stain tubes.

   ii. If emissions are determined to be greater than 0.3 lb/hr, the H_2S from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to sulfur dioxide. H_2S emissions shall be reduced by a minimum of 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]

   iii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 180 Co-Processor Heater (H-6701). Emissions from H-6701 were based on a maximum rated capacity (HHV) of 11.8 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 0.1 grain/DSCF, except for emissions of NO_X which was based on 0.06 lb/MMBTU. Actual emissions from EU H-6701 are considered insignificant (<5 TPY).

EU	Point	Description	MMBTUH
H-6701	P-180	Co-Processor Heater	11.8

a. EU H-6701 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).

b. EU H-6701 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU. [OAC 252:100-8-6(a)(1)]

c. EU H-6701 is subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions including but not limited to: [40 CFR Part 63, Subpart DDDDD]
   i. § 63.7495 When do I have to comply with this subpart? - (a) & (d)
   ii. § 63.7500 What emission limits, work practice standards, and operating limits must I meet? - (a)(1)
   iii. § 63.7505 What are my general requirements for complying with this subpart? - (a), (b), (d) & (e)
   iv. § 63.7510 What are my initial compliance requirements and by what date must I conduct them? - (a), (c), (e) & (g)
   v. § 63.7515 When must I conduct subsequent performance tests or fuel analyses? - (a), (e) & (g)
   vi. § 63.7520 What performance tests and procedures must I use? - (a), (b), (d), & (e-g)
   vii. § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards? - (a)& (e)
   viii. § 63.7535 How do I monitor and collect data to demonstrate continuous compliance? (a) & (c)
   ix. § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards? - (a), (b), (c) & (d)
   x. § 63.7545 What notifications must I submit and when? - (a), (c), (d) & (e)
   xi. § 63.7550 What reports must I submit and when? - (a), (b), (c), (d), (e) & (g)
   xii. § 63.7555 What records must I keep? - (a) & (d)
   xiii. § 63.7560 In what form and how long must I keep my records? - (a), (b) & (c)
   xiv. § 63.7565 What parts of the General Provisions apply to me?

EUG 184 Emergency Water-Curtain Pumps (EWCP-1, EWCP-2, and EWCP-3). Emissions from the EWCP are based on 100 hours of operation a year, a maximum fuel input of 34.2 gal/hr, a diesel fuel heating value of 19,300 BTU/lb, a fuel sulfur content of 0.05% by weight, and AP-42, Section 3.4 (10/96). Emissions from EU EWCP-1, EWCP-2, and EWCP-3 are considered insignificant (<5 TPY).

EU	Point	Make/Model	HP	Const. Date
EWCP-1	P-185	Caterpillar 3412	800	2004
EWCP-2	P-186	Caterpillar 3412	800	2004
EWCP-3	P-187	Caterpillar 3412	800	2004

a. EU EWCP-1, EWCP-2, and EWCP-3 shall not operate more than 100 hours per year each, except for emergencies, based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
b. EU EWCP-1, EWCP-2, and EWCP-3 shall be fitted with non-resettable hour-meters.
c. The permittee shall record the number of hours each engine is operated each month.
d. EU EWCP-1, EWCP-2, and EWCP-3 shall only be fired with diesel fuel with a sulfur content of less than 0.05% by weight (on-road low-sulfur diesel performance specification). [OAC 252:100-31]
e. The permittee shall maintain records of the diesel fuel purchase receipts documenting the sulfur content for each delivery of diesel fuel or shall determine and record the fuel sulfur content for each delivery of diesel fuel for the generators. [OAC 252:100-43]
f. A serial number or another acceptable form of permanent (non-removable) identification shall be on each engine.

EUG 185 VOC Railcar Loading Station. Emissions from the VOC Railcar Loading Station are based on the following: an hourly loading limit of 13,200 gallons/hour of gasoline/alkylate; an annual loading limit of 733,505 bbl/yr of gasoline/alkylate; combustion of the loading emissions in the asphalt Blowstill, and the following: VOC: 10 mg/L loaded; NO_X and CO: AP-42 (1/95), Section 13.5.

EU	Point	Loading Rack	Loading Arm
RCALOAD 900	P-185	1	1

a. All emissions from the VOC Railcar Loading Station shall be vented through the Asphalt Blowstill Incinerator (HI-801).
b. The amount of gasoline/alkylate loaded at the VOC Railcar Loading Station shall not exceed 13,200 gallons/hr based on a daily average or 733,505 bbl/year based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
c. The VOC Railcar Loading Station is subject to NESHAP, 40 CFR Part 63, Subpart CC and shall comply with all applicable requirements. [40 CFR 63, NESHAP, Subpart CC]
    i. § 63.642 General Standards.
    ii. § 63.650 Gasoline Loading Rack Provisions.
    iii. § 63.654 Reporting and Recordkeeping Requirements.

EUG 186 LPG Loading Station. Emissions from the LPG Loading Station are based on the throughputs shown below and the emission factor from NESHAP, Subpart R for VOC: 10 mg/L loaded.

EU	Point	Loading Bays	Loading Arm
LPG	F-115	1	1
			2
			3
			4

	Throughput	Emissions
Station (EU)	**BPY**	**TPY**
Railcar Loading (LPG)	857,513	14.7
Tank Truck Loading (LPG)	599,603	13.3
Unloading (LPG)	642,515	6.5

a. The throughputs of the LGP loading shall not exceed the throughputs shown above based on 12-month rolling totals. [OAC 252:100-8-6(a)(1)]

EUG 200 Fugitive Equipment Leaks. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Number Items	Type of Equipment
FUGEL	18,145	Valves
	32,988	Connectors
	42	Compressor Seals
	594	Pump Seals
	465	Other

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. § 63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. § 63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. § 63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).
b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 201 Wastewater Fugitive Equipment Leaks. Emissions from wastewater fugitive equipment leaks were estimated based on the number of equipment items multiplied by a standard emission factor (0.032 kg/hr/source) and are estimated at 154.3 TPY.

EU	Number Items	Type of Equipment
WWFUG	470	Sewer Cups (P-Trap)
	26	Junction Boxes
	21	Miscellaneous

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. § 63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. § 63.647 Wastewater Provisions; and
   iii. § 63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

EUG 224 & 225 Asphalt and No. 6 Fuel Oil Railcar and Truck Loading.

EU	Point	Loading Bays	Loading Arm
AsRail	F-124	2	1
			2
			3
			4
			5
EU	**Point**	**Loading Bays**	**Loading Arm**
AsTruk	F-125	4	1
			2
			3
			4
			5
			6
			7

Loading Station (EU)	Throughput BPY	Emissions TPY
Railcar Loading (AsRail)	4,745,000	16.68
Tank Truck Loading (AsTruck)	191,625	0.01

The emissions are based on AP-42 (1/95), Section 5.2 and the listed throughputs.

a. The throughput of EU AsRail shall not exceed the throughputs shown above based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
b. The temperature of the asphalt loaded shall not exceed 160 ºF. [OAC 252:100-8-6(a)(1)]
c. The temperature of the asphalt being loaded shall be measured and recorded at least once daily. [OAC 252:100-8-6(a)(3)]

3. Certain equipment within the refinery is subject to NSPS, 40 CFR Part 60, Subpart QQQ and all affected equipment shall comply with all applicable requirements.

[40 CFR Part 60, NSPS, Subpart QQQ]

a. § 60.692–1 Standards: General.
b. § 60.692–2 Standards: Individual drain systems.
c. § 60.692–3 Standards: Oil-water separators.
d. § 60.692–4 Standards: Aggregate facility.
e. § 60.692–5 Standards: Closed vent systems and control devices.
f. § 60.692–6 Standards: Delay of repair.
g. § 60.692–7 Standards: Delay of compliance.
h. § 60.693–1 Alternative standards for individual drain systems.
i. § 60.693–2 Alternative standards for oil-water separators.
j. § 60.695 Monitoring of operations.
k. § 60.696 Performance test methods and procedures and compliance provisions.
l. § 60.697 Recordkeeping requirements.
m. § 60.698 Reporting requirements.

4. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable requirements. [40 CFR Part 61, NESHAP, Subpart FF]

a. § 61.342 Standards: General.
b. § 61.343 Standards: Tanks.
c. § 61.344 Standards: Surface Impoundments.
d. § 61.345 Standards: Containers.
e. § 61.346 Standards: Individual drain systems.
f. § 61.347 Standards: Oil-water separators.
g. § 61.348 Standards: Treatment processes.
h. § 61.349 Standards: Closed-vent systems and control devices.
i. § 61.350 Standards: Delay of repair.
j. § 61.351 Alternative standards for tanks.
k. § 61.352 Alternative standards for oilwater separators.
l. § 61.353 Alternative means of emission limitation.
m. § 61.354 Monitoring of operations.
n. § 61.355 Test methods, procedures, and compliance provisions.
o. § 61.356 Recordkeeping requirements.
p. § 61.357 Reporting requirements.

5. Certain equipment within the refinery is subject to NESHAP, 40 CFR Part 63, Subpart CC and all affected equipment shall comply with all applicable requirements.

[40 CFR Part 63, NESHAP, Subpart CC]

a. § 63. 63.642 General Standards
b. § 63.643 Miscellaneous Process Vent Provisions
c. § 63.644 Monitoring for Miscellaneous Process Vents
d. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
e. § 63.646 Storage Vessel Provisions
f. § 63.647 Wastewater Provisions

g. § 63.648 Equipment Leak Standards
h. § 63.652 Emission Averaging Provisions
i. § 63.653 Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging
j. § 63.654 Reporting and Recordkeeping Requirements
k. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

6. Site remediation activities at the refinery are subject to NESHAP, 40 CFR Part 63, Subpart GGGGG and the refinery shall comply with all applicable requirements including but not limited to: [40 CFR Part 63, NESHAP, Subpart GGGGG]

a. Your site remediation is not subject to 40 CFR Part 63, Subpart GGGGG, except for the recordkeeping requirements specified in § 63.7881(c), if the site remediation meets the all of the conditions in .§ 63.7881(c)(1) through (3). [§ 63.7881(c)]
   i. Before beginning site remediation, you shall determine, for the remediation material that you will excavate, extract, pump, or otherwise remove during your site remediation, that the total quantity of HAP listed in Table 1 of 40 CFR Part 63, Subpart GGGGG, which is contained in the material is less than 1 megagram per year (Mg/yr). [§ 63.7881(c)(1)]
   ii. You shall prepare and maintain at your facility written documentation to support your determination of the total HAP quantity used to demonstrate compliance with § 63.7881(c)(1). This documentation must include a description of your methodology and data you used for determining the total HAP content of the material. [§ 63.7881(c)(2)]
   iii. This exemption may be applied to more than one site remediation at your facility provided that the total quantity of the HAP listed in Table 1 of 40 CFR Part 63, Subpart GGGGG for all of your site remediations exempted under this provision is less than 1 Mg/yr. [§ 63.7881(c)(3)]

7. Until 12 consecutive months of data has been collected to determine the 12-month rolling totals and averages applicable to the facility, the facility shall fill the missing data for the previous months with an estimated average monthly figure based on the applicable rolling total or average divided by 12. If there exists enough data to determine the values for the previous months, it can be used to determine the applicable 12-month rolling totals or averages. [OAC 252:100-8-6(a)(3)]

8. The permittee shall maintain records as specified in Specific Condition 1 and 2 including but not limited to those listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-43]

a. Records showing compliance with 12-month rolling totals (monthly) and 12-month rolling averages (daily and monthly) established in Specific Conditions 1 and 2.
b. Records showing compliance with emission limits (monthly) established in Specific Conditions 1 and 2.
c. Heater fuel usage (monthly) and heat content (quarterly).

d. The catalyst recirculation rate and the feedstock sulfur content of the catalytic reforming unit (quarterly).
e. The CO emission testing for the catalytic reforming unit (quarterly or semi-annual).
f. The flow rate and ammonia concentration of the WWTP being sent to the WWTP incinerator (weekly or monthly).
g. The WWTP Incinerator combustion zone temperature (daily).
h. The hours of operation of the EWCP.
i. The EWCP diesel fuel sulfur content (each delivery).
j. Records required by NSPS, Subparts Dc, Kb, J, GGG, and QQQ and NESHAP, Subparts CC, FF, and UUU.
k. Operating hours for EU EEQ-8801, EEQ-80001, and C-80018 (monthly and 12-month rolling totals).
l. Visible emission observations (date, time, and reading).

9. When monitoring shows an exceedance of any of the limits of Specific Condition No. 1 or 2, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions. [OAC 252:100-9]

10. No later than 30 days after each anniversary date of the issuance of the Part 70 operating permit for this facility, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of the Part 70 operating permit. The following specific information for the past year is required to be included: [OAC 252:100-8-6 (c)(5)(A) & (D)]

a. Summary of records showing compliance with the 12-month rolling totals and 12-month rolling averages established in Specific Conditions 1 and 2 (monthly).
b. Summary of records showing compliance with the emission limits established in Specific Conditions 1 and 2 (monthly).
c. Summary of the records showing compliance with the catalytic reforming unit catalyst recirculation rate, feedstock sulfur content, and CO emission limitations (quarterly or semi-annual).
d. Summary of the flow rate and ammonia concentrations of the waste gases being vented to the WWTP Incinerator and (weekly or monthly).
e. Summary of exceedances of the minimum temperature limitation of the WWTP Incinerator (daily).

11. This permit supercedes Permit No. 98-172-C (M-18) (PSD) and 98-172-C (M-15) (PSD) which are now null and void.

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(December 6, 2006)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All terms and conditions (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[40 CFR §70.6(b), OAC 252:100-8-1.3 and 8-6 (a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from emergency conditions and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV. [OAC 252:100-8-6 (a)(3)(C)(iii)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6 (a)(3)(C)(iv)]

C. Oral notifications (fax is also acceptable) shall be made to the AQD central office as soon as the owner or operator of the facility has knowledge of such emissions but no later than 4:30 p.m. the next working day the permittee becomes aware of the exceedance. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Every written report submitted under OAC 252:100-8-6 (a)(3)(C)(iii) shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iii)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. Unless a different retention period or retention conditions are set forth by a specific term in this permit, these records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), 8-6 (c)(1), and 8-6 (c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions as existing at the time of sampling or measurement.

[OAC 252:100-8-6 (a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. [OAC 252:100-8-6 (a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II of these standard conditions.

[OAC 252:100-8-6 (a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under OAC 252:100-8-6 and OAC 252:100-43 shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality. [40 CFR §70.6(a), 40 CFR §51.212(c)(2), 40 CFR § 70.7(d), 40 CFR §70.7(e)(2), OAC 252:100-8-6 (a)(3)(A)(iv), and OAC 252:100-43]

The reporting of total particulate matter emissions as required in Part 70, PSD, OAC 252:100-19, and Emission Inventory, shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter PM_{10}. NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5). [US EPA Publication (September 1994). PM_{10} Emission Inventory Requirements - Final Report. Emission Inventory Branch: RTP, N.C.]; [Federal Register: Volume 55, Number 74, 4/17/90, pp.14246-14249. 40 CFR Part 51: Preparation, Adoption, and Submittal of State Implementation Plans; Methods for Measurement of PM_{10} Emissions from Stationary Sources]; [Letter from Thompson G. Pace, EPA OAQPS to Sean Fitzsimmons, Iowa DNR, March 31, 1994 (regarding PM_{10} Condensables)]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.
[OAC 252:100-8-6 (c)(5)(A), (C)(v), and (D)]

B. The certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements.
[OAC 252:100-8-6 (c)(5)(C)(i)-(iv)]

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete.
[OAC 252:100-8-5 (f) and OAC 252:100-8-6 (c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5 (e)(8)(B) and OAC 252:100-8-6 (c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6 (c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6 (d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6 (d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, -5-2.2, and OAC 252:100-8-6 (a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6 (a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1 (d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6 (a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6 (c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6 (a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6 (a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within 10 days after such date.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112 (G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation, reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6 (a)(7)(C) and OAC 252:100-8-7.2 (b)]

B. The DEQ will reopen and revise or revoke this permit as necessary to remedy deficiencies in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.

C. If “grandfathered” status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.

(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6 (c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):
[OAC 252:100-8-6 (c)(2)]

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

SECTION XIV. EMERGENCIES

A. Any emergency and/or exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance.
[OAC 252:100-8-6 (a)(3)(C)(iii)(II)]

B. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met.
[OAC 252:100-8-6 (e)(1)]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:
[OAC 252:100-8-6 (e)(2), (a)(3)(C)(iii)(I) and (IV)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;
(4) the permittee submitted timely notice of the emergency to AQD, pursuant to the applicable regulations (i.e., for emergencies that pose an "imminent and substantial danger," within 24 hours of the time when emission limitations were exceeded due to the emergency; 4:30 p.m. the next business day for all other emergency exceedances). *See OAC 252:100-8-6(a)(3)(C)(iii)(I) and (II).* This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken; and
(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6 (e)(3)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6 (a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list. [OAC 252:100-8-2]

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or federal applicable requirement applies is not trivial even if included on the trivial activities list. [OAC 252:100-8-2]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6 (a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of 7 days, or 24 hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this subsection.[OAC 252:100-8-6 (f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(3) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. [OAC 252:100-25]

(5) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(6) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(7) Volatile Organic Compound (VOC) storage tanks built after December28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(8) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances. [40 CFR 82, Subpart A]

1. Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4.
2. Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13.
3. Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B. [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166.
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158.
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Sources' Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in Oklahoma Administrative Code 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 CFR § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 CFR § 70.8(a) and (c).
(5) The DEQ complies with 40 CFR § 70.8 (c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 CFR § 70.8 (d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8 (a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3 (a), (b), and (c), and by EPA as provided in 40 CFR § 70.7 (f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

Valero Energy Corporation
TPI Petroleum, Inc.
Attn: Mr. John Shriver, P.E.
Environmental Manager
Post Office Box 188
Ardmore, OK 74302

Re: Construction Permit No. **98-172-C (M-19) (PSD)**
Valero Ardmore Refinery
Ardmore, Carter County

Dear Mr. Shriver:

Enclosed is the permit authorizing operation of the referenced facility. Please note that this permit is issued subject to the standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact me at eric.milligan@deq.state.ok.us or (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 98-172-C (M-19) (PSD)

Valero Energy Company - Oklahoma,

having complied with the requirements of the law, is hereby granted permission to construct/modify the Valero Ardmore Refinery, located in Sections 16, 17, 20, & 21, T4N, R2E, in Carter County, Oklahoma, in accordance with this permit, subject to Standard Conditions dated December 6, 2006, and the Specific Conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division **Date**